ARIZONA WATER COMPANY

Docket No. W-1445A-02-0619

2002 RATE HEARING EXHIBIT NO. ___

For Test Year Ending 12/31/01

PREPARED

DIRECT TESTIMONY & EXHIBITS

OF

William M. Garfield

ARIZONA WATER COMPANY

Direct Testimony of

William M. Garfield

I. Introduction and Qualifications

Q. WHAT IS YOUR NAME, EMPLOYER AND OCCUPATION?

A. My name is William M. Garfield. I am employed by Arizona Water Company (the "Company") as Vice President of Operations.

Q. PLEASE DESCRIBE YOUR WORK EXPERIENCE, EDUCATIONAL BACKGROUND AND PROFESSIONAL AFFILIATIONS.

A. Since my initial employment with the Company in February 1984, I have held the positions of Engineer, Senior Engineer, Operations Manager, and currently hold the position of Vice President of Operations, which I have held since September of 1996.

I completed my undergraduate work at Southern Illinois University at Carbondale and received a Bachelor of Science degree with honors in Thermal and Environmental Engineering. I have taken post-graduate course work at Arizona State University in Civil Engineering, including coursework in hydrology, water and wastewater treatment and statistics. I am a member of Tau Beta Pi, a national honorary engineering society.

I am also a member of the American Water Works Association, the Arizona Water and Pollution Control Association and serve on the American Water Works Association's Water Meter Standards Committee. I have been active in numerous water industry stakeholder groups with the Arizona Department of Environmental Quality and the Arizona Department of Water Resources.

II. Purpose and Extent Of Testimony

Q. WHAT IS THE PURPOSE AND EXTENT OF YOUR TESTIMONY?

A. The purpose of my testimony is to support the Company's exhibits on tank maintenance accrual accounts, chlorination operating and maintenance costs, and water sampling. I will also provide testimony about regulatory changes that will have a significant impact on the Company. In particular, I will address the United States Environmental Protection Agency's ("EPA") reduction in the arsenic maximum contaminant level ("MCL") from 50 parts per billion ("PPB") to 10 PPB.

III. Description Of Company's Tank Maintenance Program

Q. WOULD YOU PLEASE EXPLAIN THE COMPANY'S TANK MAINTENANCE PROGRAM?

A. Yes. The Company's tank maintenance program includes routine tank coating inspection, interior tank coating scheduled at 14-year intervals, and exterior tank coating scheduled at 7-year intervals. The Company developed this maintenance program over the past 47 years to provide water storage tank protection through scheduled inspections and the scheduled application and maintenance of tank coatings. In this manner, the Company is able to maximize the useful life of its water storage tanks.

Q. HOW DID THE COMPANY ARRIVE AT THE 14 AND 7-YEAR COATING INTERVALS?

A. The Company's experience shows that, on average, the interior of a water storage tank should be coated every fourteen years or sooner to maintain the tank's useful life. Although actual coating frequencies may vary slightly due to various factors, this schedule has historically resulted in the most cost-effective coating program.

Extending schedules beyond this period of time could result in accelerated metal loss and shortened tank life.

In addition, the Company's experience has shown that the exterior surfaces of water storage tanks should be coated every seven years to maintain a suitable exterior appearance. Exterior surfaces degrade primarily due to ultraviolet rays from sunlight, resulting in chalking and cracking of the tank coating. Recent advances in tank coatings, coating methods, and approaches to maintaining the life and appearance of exterior coating systems have resulted in substantial improvements in the appearance of water storage tanks. These advancements have also postponed the need for commercial blasting of exterior tank coatings until after the third or fourth coating has been applied, which can reduce the cost of maintaining the water storage tanks.

Q. **HAS THE COST OF MAINTAINING WATER STORAGE TANKS CHANGED SINCE THE COMPANY'S LAST GENERAL RATE PROCEEDING?**

A. Yes. Tank coating costs have increased since 1990 for a number of reasons, including increased inspection costs, regulatory oversight, and product and labor costs. In addition, the types of coatings used today are designed to use a higher volume of solids and less solvents to reduce airborne emissions, which makes the application of coatings more difficult. The equipment needed to apply such a coating is also more specialized than it was 10 years ago.

The result of these changes is that the cost of coating interior surfaces of the Company's water storage tanks has increased from $1.25 per square foot in 1990 to as much as $3.04 per square foot in 2001. Similarly, the cost of coating exterior surfaces of water storage tanks has increased from $1.25 per square foot in 1990 to as much as $2.62 per square foot in 2001. In addition, the Company has increased the number of water storage tanks in service. Since 1990, the Company has added seven tanks in the Company's Eastern Group systems, with the result that approximately 195,000 square feet of additional painted surfaces must be maintained. These costs are shown in the Company's Schedule C-2, and identified as Adjustment #15.

IV. Description Of Company's Chlorination Program

Q. WOULD YOU PLEASE EXPLAIN THE BENEFITS OF THE COMPANY'S CHLORINATION PROGRAM?

A. Certainly. State and Federal Safe Drinking Water Standards require that water supplies and water distribution systems be kept free of bacteria. The only practical way to make sure that this standard is met is through the disinfection of water supplies and the maintenance of a free chlorine residual in water distribution systems. Public health authorities and the water industry have long recognized chlorination as the preferred means of disinfection. In addition, maintaining a free chlorine residual in water distribution systems limits or prevents bacteria re-growth and microbiological contamination that could enter the water distribution system and ultimately protects the Company's customers from waterborne disease outbreaks.

Q HAVE THE COSTS OF CHLORINATION ALSO INCREASED SINCE THE COMPANY'S LAST GENERAL RATE CASE PROCEEDING?

A. Yes, for a number of reasons. A major reason is the increased cost of operating and maintaining the chlorination equipment used to dispense tablet and liquid chlorine.

A second reason is that there are now more chlorination units in operation due to water system growth and the implementation of chlorination where it was not previously required. The costs associated with the increased number of chlorination units will increase over time until full chlorination is achieved for all existing and additional sources of supply in each water system. To date, within the Eastern Group, all water systems are nearly fully chlorinated. Additional chlorination units will be added in the future as new sources of supply are brought online, as additional chlorination units are added to water systems that are not yet fully chlorinated, and as chlorination booster systems are installed to increase chlorine residuals in remote areas of larger, complex water distribution systems.

V. Description and Discussion Of The Company's Water Quality Sampling Program

Q. CONCERNING WATER QUALITY SAMPLING, WHAT CHANGES HAVE RESULTED IN INCREASED OPERATING COSTS FOR THE COMPANY'S WATER SYSTEMS SINCE ITS LAST GENERAL RATE PROCEEDING?

A. Since 1990, water quality sampling requirements have changed significantly, primarily due to the requirements associated with the EPA's implementation of the Safe Drinking Water Act. The Arizona Department of Environmental Quality ("ADEQ") adopted these requirements in Arizona's Safe Drinking Water Rules. Since 1990, the number and type of contaminants that must be monitored have increased substantially. In addition, for systems where water treatment is necessary to comply with the new arsenic MCL, additional testing will be required for arsenic and contaminants affected by, or affecting, the type of treatment to remove arsenic selected for each water system. In addition, ADEQ recently adopted amendments to the Safe Drinking Water Rules that require microbiological particulate analysis (MPA) testing for water supplies located near surface waters or ephemeral washes. MPA tests cost an average of $250.00 per test, and multiple tests are necessary for wells that require such testing. The net effect of these regulatory changes is that costs have increased significantly and will continue to do so.

In addition, in 1998, the Arizona Legislature created a program, known as the Monitoring Assistance Program ("MAP"), under which ADEQ performs the water quality monitoring and reporting for most water systems. The MAP covers the majority of water quality parameters; however, water system operators must monitor for the remaining water quality parameters. Participation in the MAP is mandatory for systems serving a population of up to 10,000 people, and voluntary for systems serving a population over 10,000 people. Under the MAP, ADEQ assesses the Company for annual charges on a per meter basis for all of the Eastern Group water systems, except Apache Junction and San Manuel.

The Company has chosen not to participate in the MAP for water systems serving a population over 10,000, such as Apache Junction, because the Company is able to monitor these systems at a lower cost than ADEQ. However, all other systems in the Eastern Group, except for San Manuel, must participate in the MAP. The Company may be required to participate in the MAP for its San Manuel water system in the near future when its current water supplier reclassifies its water operation such that it becomes subject to the MAP. The Company's cost of participating in the MAP exceeds the monitoring costs for the same water systems prior to the required participation in the MAP.

VI. Discussion Of and Recommendations Concerning New Arsenic Maximum Contaminant Level

Q. WHAT OTHER REGULATORY CHANGES DOES THE COMPANY FACE IN THE NEAR FUTURE?

A. At this time, the primary risk that the Company faces from changing regulations is the impact of the EPA's reduction in the arsenic MCL from 50 PPB to 10 PPB. This change will have a significant impact on the Company. All of its water systems are served primarily with groundwater. Groundwater in many portions of the southwestern region of the United States and, more importantly, in many locations in Arizona is naturally high in arsenic. The Eastern Group systems are served entirely with groundwater, except for Apache Junction, which receives over 70 percent of its potable supplies from groundwater.

Q. HOW WILL THE COMPANY COMPLY WITH THE NEW ARSENIC MCL?

A. The Company must design, construct and operate as many as 50 arsenic removal water treatment facilities company-wide with a combined total treatment capacity of 60.65 million gallons per day ("MGD"). In the Eastern Group alone, as many as 21 treatment facilities, with a combined treatment capacity of 23 MGD, will have to be in operation prior to January 23, 2006, to comply with the new arsenic MCL.

The most likely treatment methods for arsenic removal include: 1) conventional filtration - surface water type, i.e., adding coagulants such as ferric chloride or alum to raw water, allowing the arsenic to bind with the precipitants that will form and then filtering out the waste solids, and 2) adsorption, where untreated water is chemically pre-treated and then passed through a filter media that causes the arsenic to bind with or be adsorbed to the filter media. The second form of treatment may also require the addition of chemicals to minimize corrosivity.

Both treatment methods require that the arsenic removed be disposed of in a manner that complies with applicable EPA and ADEQ requirements. Those requirements will add significant cost to the water treatment facilities that remove arsenic.

Q. HAS THE COMPANY DETERMINED THE FINANCIAL IMPACT OF THE REDUCTION IN THE MCL FOR ARSENIC?

A. Yes. In a study prepared for a report to the EPA in September 2000, the Company estimated that a capital cost of $12.5 million would be incurred to comply with the new arsenic MCL for the water systems in the Eastern Group. Company-wide, the Company's total capital cost to meet the new arsenic MCL of 10 PPB is estimated at $30 million. Also, since the Company prepared this original study, additional sources of supply have been identified that will also require treatment for arsenic within systems where treatment was not anticipated, such as the new Bisbee water supply well that is currently under construction. This will require a significant increase in the Company's water utility plant.

In addition, compliance with the more stringent requirements for water treatment to remove arsenic and to dispose of the arsenic will result in substantial increases in ongoing operation and maintenance costs. The Company estimates that operation and maintenance expenses relating to water treatment facilities to remove arsenic will exceed $6.3 million annually for the total Company and $2.6 million annually for the Eastern Group.

Michael J. Whitehead, the Company's Vice President of Engineering, will provide more detailed capital cost information and a schedule of treatment plant construction in his direct testimony. Likewise, Ralph J. Kennedy, the Company's Vice President and Treasurer, will provide information concerning the rate impact of the new arsenic MCL and methods of recovering the costs of the required treatment in his direct testimony.

Q. HOW WILL WATER TREATMENT TO REMOVE ARSENIC IMPACT RATES FOR AN AVERAGE RESIDENTIAL CUSTOMER?

A. In a September 6, 2000 letter to the EPA, the Company estimated that water systems in the Eastern Group where one or more sources of supply exceed the EPA's then-proposed arsenic MCL of 10 PPB, rates would have to increase by an average of 48 percent for an average residential customer to cover the cost of constructing and operating treatment facilities to comply with the new MCL. This estimate did not include the impact on the Bisbee system, where treatment for arsenic removal will be required for the new Bisbee well.

Q. WHEN WILL THE COMPANY BE REQUIRED TO MEET THE EPA'S NEW ARSENIC MCL?

A. All community systems and non-transient non-community water systems must comply with the new arsenic MCL by January 23, 2006. To meet this deadline for the Eastern Group water systems, the Company must begin construction of the treatment facilities no later than early 2003 to complete the construction of all of the treatment facilities before the deadline. Mr. Whitehead will address the construction schedule in more detail in his direct testimony.

Q. WILL THE NEW ARSENIC MCL AFFECT THE COMPANY'S WATER SYSTEM OPERATIONS? IF SO, WHAT ARE THE IMPACTS?

A. Yes. The new arsenic MCL will impact the Company's water system operations. The major impacts will include increased operator (employee) training, increases in the number of personnel required to operate and maintain treatment facilities, increased water quality testing, possible reductions in the availability of water supplies due to quality limitations, limitations on treatment and/or blending, among other factors. The complexity and operational requirements of each treatment facility will determine the number of additional employees that will be needed. However, I estimate that a minimum of eight additional employees will be needed to operate and maintain water treatment facilities to remove arsenic for the total Company, which includes four additional employees for the Eastern Group.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY IN THIS MATTER?

A. Yes.

ARIZONA WATER COMPANY

Docket No. W-1445A-02-0619

2002 RATE HEARING EXHIBIT NO. ___

For Test Year Ending 12/31/01

PREPARED

DIRECT TESTIMONY & EXHIBITS

OF

Sheryl L. Hubbard

EXHIBIT

A-11

~~Admitted~~

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ARIZONA WATER COMPANY

Direct Testimony of

SHERYL L. HUBBARD

I. Introduction and Qualifications

Q. WHAT IS YOUR NAME, EMPLOYER AND OCCUPATION?

A. My name is Sheryl L. Hubbard. I am employed by Arizona Water Company (the "Company" or "AWC") as Manager of Rates and Regulatory Accounting.

Q. PLEASE DESCRIBE YOUR WORK EXPERIENCE AND EDUCATIONAL BACKGROUND.

A. I graduated from Michigan State University with a Bachelor of Arts degree in Accounting and I am a certified public accountant. I have twenty-three years of experience with public utility accounting and regulation having been an auditor/audit manager with the Michigan Public Service Commission for seventeen of those years. During my employment with the Michigan Commission, my responsibilities included preparation of revenue requirement calculations for water, steam and electric utilities. Subsequent to my employment with the Michigan Public Service Commission, I was employed by the Arizona Corporation Commission ("ACC") as the Chief of the Accounting and Rates section. Following my employment with the ACC, I joined Citizens Communications Company ("Citizens") as a Regulatory Accounting Manager in its Arizona Gas division. My responsibilities with Citizens included assuring compliance with applicable state statutes and regulatory rules and decisions as well as preparation of rate cases and other regulatory filings with state regulatory agencies in Arizona and Colorado. Subsequent to my employment with Citizens Communications Company, I joined Arizona Water Company in my current position as Manager of Rates and Regulatory Accounting.

II. <u>Purpose and Extent of Testimony</u>

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony in this proceeding is to present the development of rate base, working capital requirements, and net operating income for the Eastern Group water systems of the Company (the "Eastern Group") for the historical twelve month period ended December 31, 2001 and to sponsor the calculation of the associated increase in gross revenue requirement of each system. The systems that comprise the Eastern Group and are the subject of this application are Apache Junction, Superior, Bisbee, Sierra Vista, San Manuel, Oracle, Winkelman and Miami.

Q. DOES YOUR TESTIMONY IN THIS PROCEEDING INCORPORATE RECOMMENDATIONS OF OTHER COMPANY WITNESSES?

A. Yes it does. My testimony in this proceeding incorporates recommendations sponsored by Ralph J. Kennedy, Michael J. Whitehead, William M. Garfield, and Thomas M. Zepp.

III. <u>Exhibits and Associated Schedules</u>

Q. PLEASE IDENTIFY THE EXHIBITS AND ASSOCIATED SCHEDULES YOU ARE SPONSORING.

A. I am sponsoring the following exhibits:

Schedule A-1 – AWC Computation of Increase In Gross Revenue Requirements

Schedule A-2 – AWC Summary of Operations

Schedule A-3 – AWC Summary of Capital Structure

Schedule A-4 – AWC Construction Expenditures and Gross Utility Plant In Service

Schedule A-5 – AWC Summary of Cash Flows

Schedule B-1 – AWC Summary of Original Cost Rate Base Elements

Schedule B-2 – AWC Original Cost Rate Base Pro Forma Adjustments

Schedule B-5 – AWC Computation of Working Capital

Schedule B-6 - AWC Summary of Lead/Lag Working Cash Requirements

Schedule C-1 – AWC Adjusted Test Year Income Statement

Schedule C-2 – AWC Income Statement Pro Forma Adjustments

Schedule C-3 - AWC Computation of Gross Revenue Conversion Factor

Schedule E-1 Comparative Balance Sheets-Total Company-Prior Years 1999 & 2000 and Test Year 2001

Schedule E-2 Comparative Income Statements-Total Company and Eastern Group-Prior Years 1999 & 2000 and Test Year 2001

Schedule E-3 Comparative Statement of Cash Flows-Total Company- Test Year 2001 and Prior Years 2000 & 1999

Schedule E-4 Statement of Changes in Stockholder's Equity-Total Company-Prior Years 1999 & 2000 and Test Year 2001

Schedule E-5 Detail of Utility Plant at End of Prior Year 2000 and Test Year 2001

Schedule E-6 Comparative Operating Income Statements-Test Year 2001 and Prior Years 2000 & 1999

Schedule E-7 Operating Statistics-Test Year 2001 and Prior Years 2000 & 1999

Schedule E-8 Taxes Charged to Operations-Test Year 2001 and Prior Years 2000 & 1999

Schedule F-1 Projected Income Statements-Eastern Group-Test Year 2001 and Projected Year 2002

Schedule F-2 Statement of Cash Flows-Present and Proposed Rates-Total Company-Test Year 2001 and Projected Year 2002

Schedule F-3 Projected Construction Requirements-Test Year 2001 and Projected Years 2002, 2003, and 2004

Schedule F-4 Assumptions Used in Developing Projections-Eastern Group-Projected Year 2002

Q. MS. HUBBARD, WERE THESE EXHIBITS PREPARED BY YOU OR UNDER YOUR DIRECTION AND SUPERVISION?

A. Yes, they were.

IV. <u>Revenue Requirement – Summary Schedules</u>

Q. PLEASE EXPLAIN SCHEDULE A-1.

A. Schedule A-1 is a three-page schedule titled "Computation of Increase In Gross Revenue Requirements" for the individual systems composing the Eastern Group. The increase in gross revenue for each system represents the change in gross revenues that the Company has determined is necessary to continue to provide service to its customers while providing an opportunity to earn a reasonable rate of return on its investments dedicated to that service. For purposes of this proceeding, the increase in gross revenue requirement for the Eastern Group based on a 2001 test year is $4,256,510.

Q. **PLEASE EXPLAIN SCHEDULE A-2.**

A. Schedule A-2 titled "Summary Results of Operations" contains operating history for the test year 2001, 2000 and 1999 as well as projected year 2002 for the Eastern Group and on a Total Company basis. The test year 2001 figures on this exhibit are presented as recorded in the accounting records of the Company and are also adjusted for the pro forma changes identified in the Company's application.

Q. **PLEASE EXPLAIN SCHEDULE A-3.**

A. Schedule A-3 titled "Summary of Capital Structure" summarizes the debt and equity of the Company allocated to the Eastern Group for test year 2001, 2000, and 1999 as well as projected year 2002. The test year 2001 figures are presented unadjusted as well as adjusted for pro forma changes recommended in the Company's application.

Q. **PLEASE EXPLAIN SCHEDULE A-4.**

A. Schedule A-4 is a five-page schedule titled "Construction Expenditures and Gross Utility Plant in Service". This exhibit presents the historical construction expenditures for test year 2001, 2000, and 1999 as well as three years of projected expenditures. The information is delineated by individual system, Eastern Group and Total Company. This schedule also contains annual cost data for net plant placed in service and balances of gross utility plant in service for the same time periods shown for construction expenditures. Company witness Michael J. Whitehead is sponsoring the explanation of construction expenditures in this proceeding.

Q. PLEASE EXPLAIN SCHEDULE A-5.

A. Schedule A-5 titled "Summary of Cash Flows" is a statement of cash flows detailing the changes in the cash accounts for test year 2001, 2000, and 1999 on a Total Company basis.

V. <u>Rate Base Schedules</u>

Q. PLEASE EXPLAIN SCHEDULE B-1.

A. Schedule B-1 titled "Summary of Original Cost Rate Base Elements (Including Pro Forma Adjustments)" is a two-page schedule that details the development of the end of test year rate bases for the Eastern Group. Rate Base represents the investor-supplied plant facilities and other investments required to provide utility service to customers. The components typically recognized in the calculation of rate base are plant in service, accumulated depreciation and amortization, customer advances for construction, contributions in aid of construction, deferred income tax liabilities, and working capital. Other items that may be considered in the calculation of rate base on a case-by-case basis include acquisition adjustments and construction work in progress. Net plant, plant in service less the associated accumulated depreciation and amortization, is generally the largest component of rate base. The Net Plant total for the Eastern Group and each of the individual systems is shown on Line 1 of Schedule B-1. Rate base is computed by offsetting Net Plant by Customer Advances for Construction, Net Contributions In Aid of Construction, and Deferred Income Taxes. The accumulated balance of customer advances is shown on Line 2 of Schedule B-1. Line 3 of Schedule B-1 shows the Contributions in Aid of Construction, net of applicable amortizations, for the Eastern Group and the individual systems. Line

4 of the schedule shows the Accumulated Deferred Income Taxes as of the end of the test year. For ratemaking purposes, a working capital allowance is developed to adjust rate base to reflect the additional investment required for on-going utility operations over and above that amount reflected in net plant. The Allowance for Working Capital that is shown on Line 5 of Schedule B-1 is supported by calculations on Schedule B-5 and will be discussed later in this testimony.

Q. PLEASE EXPLAIN SCHEDULE B-2.

A. Schedule B-2 titled "Original Cost Rate Base Pro Forma Adjustments" is an eleven-page exhibit that details the pro forma adjustments that the Company has identified and proposed as appropriate and necessary to adjust the historical year-end plant to include all investments deemed necessary to provide satisfactory service to historical year-end customers when the rates resulting from this application become effective.

Q. PLEASE DESCRIBE THE RATE BASE COMPONENTS INCLUDED IN SCHEDULE B-2.

A. Plant in service represents the original cost of the utility property used in the provision of service to the customer. Gross utility plant in service for the Eastern Group, presented on line 1, is capitalized at $86,270,323 including pro forma adjustments. Accumulated Depreciation, the amount of annual depreciation and amortization charges on original utility investments accumulated through the end of the test year, as well as effects on depreciation and amortization charges due to pro forma adjustments to plant in service, is shown on line 2. Line 4, Construction Work in Progress ("CWIP") shows the balance at the end of the test year of construction projects not yet completed. The CWIP balance for the Eastern Group is $0 after recognizing the pro forma adjustments to transfer non-revenue producing projects completed prior to December 31, 2002 to plant in service and to exclude the outside-funded projects under construction at the end of the test year. The CWIP balance and associated pro forma adjustments are shown on line 4 of Schedule B-2. Total net plant for the Eastern Group including pro forma adjustments is $67,948,582 and is shown on Line 5 of this schedule.

Q. PLEASE DISCUSS THE PRO FORMA ADJUSTMENT IDENTIFIED AS POST TEST YEAR PLANT ADDITIONS PLACED IN SERVICE IN COLUMN (1) ON SCHEDULE B-2.

A. The pro forma adjustment labeled Post Test Year Plant Additions ("PTYPA") Placed in Service in Column (1) of Schedule B-2 quantifies the amount of investment in non-revenue producing plant that was under construction at the end of the test year and during 2002 that will be completed and transferred to plant in service through December 2002. This cut-off date should allow ample time for the Utilities Division Staff ("Staff") and other interested parties to verify that the investments are both used and useful and non-revenue producing. The portion of this pro forma adjustment associated with plant under construction at the end of the test year has been removed from the Construction Work in Progress balance shown on Line 4 and included in the gross plant in service adjustment on line 1 on Schedule B-2.

Q. PLEASE DISCUSS THE PRO FORMA ADJUSTMENT IDENTIFIED AS 12 MONTHS DEPRECIATION ON POST TEST YEAR PLANT ADDITIONS IN COLUMN (2) OF SCHEDULE B-2.

A. Column (2) of Schedule B-2 quantifies the pro forma adjustment to accumulated depreciation resulting from the depreciation expense associated with the non-revenue producing plant placed in service after the end of the test year.

Q. PLEASE DISCUSS THE PRO FORMA ADJUSTMENT IDENTIFIED AS SIX MONTHS ADDITIONAL DEPRECIATION EXPENSE ON TEST YEAR ADDITIONS IN COLUMN (3) OF SCHEDULE B-2.

A. Regardless of when additions to or retirements of plant in service occur, the Company uses a half-year convention to calculate the first year of depreciation expense. This half-year convention is also applied in the last year of the asset's depreciable life. Since only six months of depreciation expense are reflected in the income statement for any plant additions or retirements during the test year, an annualizing expense adjustment for depreciation expense is necessary to reflect an appropriate expense level to be incurred during the time when new rates will be in effect. The adjustment to reflect this depreciation annualization is shown in column (3) of Schedule B-2.

Q. PLEASE DISCUSS THE PRO FORMA ADJUSTMENT IDENTIFIED AS DEFERRED CAP CHARGES IN COLUMN (4) OF SCHEDULE B-2.

A. Since 1985, the Apache Junction system of the Eastern Group has had a contractual arrangement with the United States Bureau of Reclamation ("Bureau of Reclamation") and the Central Arizona Water Conservation District ("CAWCD") for an annual allocation of Central Arizona Project ("CAP") water. Under this contractual arrangement, the Apache Junction system has incurred an annual charge for CAP Municipal and Industrial capital charges ("M&I charges"), which the Company has been deferring. Another term of the arrangement with the

Bureau of Reclamation and CAWCD applies to the assessment of delivery charges for water delivered. Delivery charges are assessed when actual deliveries of water occur.

Q. MS. HUBBARD, HAS THE COMMISSION PREVIOUSLY ADDRESSED THE TREATMENT OF CAP WATER CHARGES FOR THE APACHE JUNCTION SYSTEM?

A. In the Company's last rate proceeding involving the Apache Junction system, which used a 1990 test year, the M&I charges deferred at that time totaled $60,000 ("pre-1991 M&I deferral"). The Commission authorized the inclusion of the deferred balance in the Company's rate base and approved an amortization to expense. Decision No. 58120 (December 23, 1992) at page 7. Additionally, the Company was authorized to accrue an allowance for funds used during construction on its deferred balance of M&I charges.

Q. PLEASE DISCUSS THE CHANGES THAT HAVE OCCURRED IN THE USE OF THE CAP WATER ALLOCATION SINCE THE ENTRY OF COMMISSION DECISION NO. 58120.

A. Prior to the entry of Decision No. 58120, the Company had been taking deliveries of its CAP water allocation only for potable consumption. Currently, a portion of the CAP allocation is treated at the Mesa treatment plant for deliveries to potable customers and the remainder of the allocation delivered is sold untreated to golf courses in the Apache Junction service area under a Non-Potable CAP Water Tariff.

Q. HOW HAVE THE CAP WATER PURCHASES BEEN REFLECTED IN THE COMPANY'S ACCOUNTING RECORDS SUBSEQUENT TO THE ENTRY OF COMMISSION DECISION NO. 58120?

A. The Company continued to defer M&I charges ("post-1990 M&I deferral") in an account separate from the pre-1991 M&I deferral, and expensed the delivery charges when incurred. In addition, the original and modified Non-Potable CAP Water Tariffs, under which service is provided to some golf courses in the Apache Junction service area, were intended to provide funds for reducing the deferred M&I charges while encouraging use of CAP water in lieu of groundwater. Revenues collected via the Non-Potable CAP Water Tariff have been used to reduce the post-1990 M&I deferral by crediting the amount billed for M&I charges under the tariff to the post-1990 M&I deferral. From the time that the Non-Potable CAP Water Tariff was authorized through the end of the test year, $1,543,400 of M&I charges have been collected from customers taking CAP water under the Non-Potable CAP Water Tariff. These funds have reduced the deferred M&I charges that would otherwise have to be recovered from the Company's other customers taking delivery of potable water. As of the end of the test year, the post-1990 M&I deferral balance was $503,098.

Q. PLEASE DISCUSS HOW THE COMPANY PROPOSES TO ADDRESS THE POST-1990 M&I DEFERRAL IN THIS PROCEEDING.

A. In this proceeding, the Company is proposing to include the post-1990 M&I deferral balance in rate base and amortize the balance over a period of time equivalent to the duration of time until the next Eastern Group rate application will be filed. The Company estimates that period of time to be approximately three years after the decision in this proceeding. Column (4) of Schedule B-2 shows the pro forma adjustment to net plant that is required to include the balance of the post-1990 M&I deferral in rate base. The adjustment reflects the balance of deferred M&I charges as of December 31, 2002. The Company is proposing that the post-1990 M&I deferral be amortized to expense over a three-year amortization period. The balance of the post-1990 M&I deferral as of December 31, 2002 is $658,588.

Q. **HAS STAFF PROVIDED ANY GUIDANCE ON CRITERIA REQUIRED TO OBTAIN COST RECOVERY OF CAP WATER ALLOCATION COSTS?**

A. Yes. Per the Commission's directive in Decision No. 62993 (November 3, 2000), Staff developed a policy statement regarding recovery of costs related to the CAP. The policy statement has been labeled Attachment D-Proposed Policy for CAP Cost Recovery and has been posted on the Commission's website.

Q. **WHAT CRITERIA IS SET FORTH REGARDING CAP COST RECOVERY IN THE STAFF'S POLICY STATEMENT?**

A. The Staff has identified four criteria for which evidence demonstrating compliance must be provided by a water company to obtain CAP cost recovery. The first requirement is for the water company to demonstrate that the CAP allocation is needed to properly serve its customers. The second requirement is that the CAP allocation will be needed by 2025. The third requirement is that a reasonable amount of the CAP allocation will actually be used by 2025. The fourth requirement is that the water company will be using all of its CAP allocation by 2034.

Q. MS. HUBBARD, IS THE COMPANY ABLE TO DEMONSTRATE COMPLIANCE WITH THE FOUR CRITERIA IDENTIFIED IN THIS POLICY?

A. Yes. The Company has been using CAP water in its certificated area to provide service to its customers since before the time that the CAP canal became operational. The deliveries of the CAP water have increased over this period of time, and in 2001, 4,538 acre-feet were scheduled and actual deliveries totaled 5,163 acre-feet. The Apache Junction system is currently scheduled to take 5,400 acre-feet in 2002, which is 90% of the 6,000 acre-feet allocation. However, actual deliveries always exceed scheduled deliveries to avoid an ordering penalty. Of these scheduled deliveries of CAP water, a portion of the deliveries will provide non-potable CAP water under the Company's Non-Potable CAP Water Tariff and the remainder will be treated at the Mesa treatment plant for the Apache Junction system's water customers taking potable water.

As a condition for approval to develop a subdivision, the Arizona Department of Water Resources ("ADWR") requires developers to obtain a Certificate of Assured Water Supply. In response to ADWR's requirement, the Company has made firm commitments to serve thirty-seven specific subdivisions in its service area using an additional 1,616 acre-feet of treated CAP water. Treating this percentage of the CAP allocation will require additional treatment capacity at the Mesa treatment plant. The Company has committed to acquire this additional capacity as part of the third phase of the Mesa treatment plant.

The Mesa treatment plant has an expansion program in effect that consists of several phases of expansion. The initial two phases of construction of the treatment facility are in service and are being used to treat the Company's current level of usage. A third phase is currently at the sixty percent design stage and expected to be completed by 2004. The dedication of the CAP allocation and the commitment to acquire the additional required treatment capacity provides the assurance of water availability on a long-term basis needed to satisfy the ADWR's assured water supply requirements allowing the thirty-seven new subdivisions to be approved.

Q. IS THE COMPANY PROPOSING ANY CHANGE IN THE RECOVERY ASSOCIATED WITH THE PRE-1991 M&I DEFERRAL?

A. Yes, the Company is requesting that the Commission authorize an adjustment to the amortization period authorized for the pre-1991 M&I deferral for the Apache Junction system. Since the entry of Decision No. 58120, which established the current amortization period, the Company has begun utilizing its CAP allocation. Currently, the entire CAP allocation is being used by the Company to provide both potable and non-potable water to its customers. The Company's CAP allocation is fully used and useful justifying current recovery of incurred costs. The Company is, therefore, requesting an amortization period that matches the amortization period of the new M&I deferral amortization, or three years. The resulting annual amortization expense is discussed in conjunction with the pro forma adjustments to the Company's operating revenues and expenses later in this testimony.

Q. HOW IS THE COMPANY PROPOSING TO TREAT PURCHASED CAP WATER COSTS IN THE FUTURE?

A. The Company will continue to retain its CAP allocation to properly serve its customers. Because the CAP allocation for the Apache Junction system is presently used and useful, it is inappropriate to continue deferring the M&I charges. The Company is proposing to expense all future purchased CAP water expenses. These expenses include both the M&I charges and the delivery charges consisting of power and an operation, maintenance and return component. The effect of this proposal on the Company's adjusted operating income is discussed in conjunction with the discussion on pro forma adjustments to operating revenues and expenses later in this testimony.

Q. PLEASE DISCUSS THE PRO FORMA ADJUSTMENT IDENTIFIED AS OUTSIDE-FUNDED CWIP IN COLUMN (5) OF SCHEDULE B-2.

A. Column (5) of Schedule B-2 is a pro forma adjustment to remove the outside-funded portion of the CWIP balance at the end of the test year and the associated customer advances from the calculation of rate base. This adjustment is necessary to match Plant in Service with the advances that have financed them.

Q. MS. HUBBARD, THE EXHIBIT IN THIS FILING DOES NOT INCLUDE SCHEDULES B-3 OR B-4. PLEASE EXPLAIN THE OMISSION OF THESE TWO SCHEDULES.

A. For purposes of this rate filing only, the Company will agree that the Commission may use its original cost rate base as its "fair value" rate base in setting new rates. Therefore, the Company has not developed a Replacement Cost New Less Depreciation ("RCND") rate base and as such has not submitted Schedules B-3 and B-4, which pertain solely to an RCND rate base.

Q. PLEASE EXPLAIN SCHEDULE B-5.

A. Schedule B-5 titled "Computation of Working Capital" is a two-page schedule presenting the working capital requirement of the Company. Working capital is a measure of investor funding of daily operating expenditures and other non-plant investments that are necessary to sustain ongoing operations of the utility. This measurement is designed to identify the average ongoing funding requirements for the test year. The components included in this working capital computation are materials and supplies inventory, prepayments, and cash working capital.

Q. PLEASE DISCUSS THE MATERIALS AND SUPPLIES INVENTORY COMPONENT OF THE WORKING CAPITAL REQUIREMENT.

A. Theoretically, materials and supplies are included as a component of working capital to provide a return on the investor's capital required to maintain a supply of materials necessary to carry on day-to-day operation and maintenance activities. The measurement of the materials and supplies inventory for working capital purposes is computed using an average of thirteen monthly balances. Use of a 13-month average reduces distortion caused if the inventory balances are volatile or experience cyclical highs and lows.

Q. PLEASE DISCUSS THE PREPAYMENTS COMPONENT OF THE WORKING CAPITAL REQUIREMENT.

A. Prepayments are included as a component of working capital to recognize an investment of funds made by the Company. Prepayments represent payments of expenses made in advance of the period to which they apply. As with the Materials and Supplies inventory discussed above, a 13-month average balance is used to quantify the working capital allowance due to investments in prepayments to be added to the Company's rate base.

Q. PLEASE DISCUSS THE REQUIRED BANK BALANCES COMPONENT OF THE WORKING CAPITAL REQUIREMENT.

A. Required bank balances on line 3 of Schedule B-5 represent the portion of the 13-month average balance for the test year allocated to the Eastern Group using the three-factor ratios.

Q. PLEASE DISCUSS THE CASH WORKING CAPITAL COMPONENT OF THE WORKING CAPITAL REQUIREMENT.

A. Cash working capital should represent the average amount of capital provided by investors, over and above the investment in plant and other rate base items, to finance cost of service during the time lag before revenues are collected. In conjunction with the other components of rate base, the overall purpose of the cash working capital component is to measure the amount of investor supplied capital required to provide service. There are several acceptable methods for computing the cash working capital component, but the Staff has adopted the use of the lead/lag methodology for determining cash working capital for large water utilities in this jurisdiction. The Company's lead/lag cash working capital calculation will be discussed in conjunction with the discussion of Schedule B-6 below.

Q. PLEASE EXPLAIN SCHEDULE B-6.

A. Schedule B-6 titled "Summary of Lead/Lag Working Cash Requirements" is a three-page schedule that details the calculation of the investor provided working cash component of the working capital calculation. To compute the working cash component of the working capital calculation, it is necessary to measure the time lag between services rendered and the receipt of revenues for those services. This measurement, referred to as the Dollar Days Revenue Lag, reflects a provision of working capital by investors and is shown on Line 1 of Schedule B-6. It is also necessary to measure the time lag between the incurrence of expenses and the payment of those expenses, which offsets the revenue lag. This is referred to as the Dollar Days Expense Lag. It reflects a use of working capital by investors and is shown on Line 2 of Schedule B-6. The net of the Dollar Days Revenue Lag and the Dollar Days Expense Lag is computed and if the Dollar Days Revenue Lag exceeds the Dollar Days Expense Lag, you have a net provision of working capital by investors. If the converse is true, you have a net provision of working capital by ratepayers.

VI. <u>Test Year Income Statements</u>

Q. PLEASE EXPLAIN SCHEDULE C-1.

A. Schedule C-1 titled "Adjusted Test Year Income Statement-Eastern Group" is a five-page exhibit setting forth the revenues and expenses for the Eastern Group and the resulting net income both on a historical unadjusted basis and an adjusted (including pro forma adjustments) basis. For the individual systems, operating revenues and operating expenses and the resulting operating income are detailed on this schedule.

VII. <u>Income Statement Pro Forma Adjustments</u>

Q. PLEASE EXPLAIN SCHEDULE C-2.

A. Schedule C-2 titled "Income Statement Pro Forma Adjustments" is a thirty-six page schedule detailing the pro forma adjustments to the historical test year operating results that the Company has identified as necessary and appropriate to properly reflect its current level of revenues and expenses. The pro forma adjustments have been presented on a system-by-system basis.

Q. PLEASE DISCUSS THE CATEGORIES OF PRO FORMA ADJUSTMENTS THAT THE COMPANY IS PROPOSING TO THE HISTORICAL TEST YEAR FIGURES FOR THE EASTERN GROUP.

A. The Company is proposing to adjust its historical test year revenue and expense levels for the following categories:

Adjustment 1 – Eliminate Sales Tax From Revenue and Expense

Adjustment 2 – Eliminate Purchased Power Adjustment Mechanism ("PPAM") Revenues, And Purchased Water Adjustment Mechanism ("PWAM") Revenues

Adjustment 3 – Eliminate Unbilled Revenue-Net

Adjustment 4 – Eliminate MAP Revenue and Expense

Adjustment 5 – Annualize Additional Customer Revenue and Expenses

Adjustment 6 – Payroll Expense Annualized

Adjustment 7 – Payroll Tax Annualized

Adjustment 8 – Pension

Adjustment 9 – Power and Water Costs Annualized

Adjustment 10 – Insurance

Adjustment 11 – Chlorination Cost Adjustment

Adjustment 12 – Water Testing Annualized

Adjustment 13 – Office Rent and Cleaning Annualized

Adjustment 14 – Paper, Billing, Postage Annualized

Adjustment 15 – Tank Maintenance-Increase Annual Accrual

Adjustment 16 – Amortization of 2001 Rate Case Expense

Adjustment 17 – Six Month Additional Depreciation Expense

Adjustment 18 – Depreciation Expense-Completed Construction

Adjustment 19 – Property Taxes Annualized

Adjustment 20 – Vehicle & Equipment Lease Costs

Adjustment 21 - Federal Income Tax

Adjustment 22 – State Income Tax

Adjustment 23 – Tax Effect of Interest Synchronization

These adjustments are all based on known and measurable changes in revenues and expenses.

Q. PLEASE EXPLAIN ADJUSTMENT 1 – ELIMINATE SALES TAX FROM REVENUE AND EXPENSE.

A. Adjustment 1 - Eliminate Sales Tax From Revenue and Expense is a pro forma adjustment to remove revenue-based taxes from operating revenues and expenses. The purpose of the adjustment is to segregate revenues collected as a result of tariffed rate schedules from total operating revenues, which includes sales taxes, ACC assessments, and the Residential Utility Consumer Office ("RUCO") assessments. The adjustment to remove sales taxes, ACC and RUCO assessments from revenues of $1,184,895 is the same amount removed from operating expenses for the Eastern Group and does not affect operating income.

Q. PLEASE EXPLAIN ADJUSTMENT 2 – ELIMINATE PPAM, PWAM.

A. Adjustment 2 – Eliminate PPAM, PWAM is a pro forma adjustment to remove the revenues collected pursuant to the Company's purchased power adjustment mechanism ("PPAM") and purchased water adjustment mechanism ("PWAM"). These revenues reflect changes in purchased power costs and purchased water costs from base levels approved in the Company's last rate case proceeding. The Company proposes that the adjustor mechanisms be reset to zero with new base levels established in this proceeding at the current level of expense. The adjustment to revenues to remove PPAM and PWAM revenues for the Eastern Group is a negative $44,371. The effect of the adjustment is an increase in operating income.

Q. PLEASE EXPLAIN ADJUSTMENT 3 – ELIMINATE UNBILLED REVENUE-NET.

A. Adjustment 3 – Eliminate Unbilled Revenue-Net is a pro forma adjustment to remove from revenues and expenses the effect of the year-end accounting process to accrue for revenues earned but not yet billed and expenses incurred but not yet invoiced. In January of each year, the prior year's unbilled revenue and expense accounting adjustments recorded in December are reversed. In December of each year, the revenues earned but not yet billed and expenses incurred but not yet invoiced are quantified and recorded as a year-end accounting adjustment. This pro forma adjustment removes the effects of these accounting adjustments. For the Eastern Group, the adjustment to remove the effects of unbilled revenue accounting is an increase in revenues of $106,640 and the adjustment to remove the effects of the expenses relating to unbilled revenue is a decrease in expenses of $13,062.

Q. PLEASE EXPLAIN ADJUSTMENT 4 – ELIMINATE MAP REVENUE AND EXPENSE.

A. Adjustment 4 – Eliminate Monitoring Assistance Program ("MAP") Revenue and Expense is the pro forma adjustment necessary to remove the surcharge revenues and test year expenses associated with the Arizona Department of Environmental Quality's ("ADEQ") MAP. The MAP provides the required testing for three categories of constituents: Inorganics, Synthetic Organic Chemicals and Volatile Organic Chemicals. The Apache Junction system has a population of over 10,000 and, therefore, is not required to participate in ADEQ's MAP. For the San Manuel system, the Company purchases the water it provides to its customers from BHP Copper Company and has been granted an exemption from MAP testing by the ADEQ. The remaining water systems in the Eastern Group are required to participate in the MAP.

For each system, the Company must pay an annual fee to ADEQ, based on a formula in ADEQ's regulations, which covers the normal testing requirements. Pursuant to the Company's Monitoring Assistance Program Surcharge tariff, MA-262, an annual filing is made with the Commission in October of each year to establish the surcharge to be effective in the forthcoming January. Any under- or over- collection of MAP expenses is rolled into the surcharge calculation for the forthcoming period. The revenues of $53,685 collected in the 2001 test year were designed to recover the 2000 MAP expense of $53,409. The surcharge that is currently charged to customers in 2002 is designed to collect the 2001 MAP expense of $44,520 less the 2000 over-recovered MAP expenses. The MAP surcharge revenues of $53,685 collected in 2001 and the MAP expenses of $44,520 recorded during 2001 should be removed from the test year operating income. Upon issuance of a decision in this docket, the annualized testing costs authorized in this proceeding for the Eastern Group systems to be reflected in subsequent MAP surcharge filings will be reset zero. Differences in the MAP costs incurred and the MAP surcharge revenues collected are more appropriately reflected in the annual surcharge filings than in this rate filing. Since participation in MAP testing is required by ADEQ for water systems serving less than 10,000 customers, costs associated with MAP compliance should be segregated and reported on the customer's bill.

There are several benefits to retaining the procedure as it is currently designed. For instance, the testing costs are outside of the control of the Company and are set by an independent State agency. Further, program changes can be reflected in rates in a more timely fashion as demonstrated in the October 2001 filing which reflects a reduced MAP expense level of $44,520 for 2001 versus the 2000 MAP expense of $53,410.

Q. PLEASE EXPLAIN ADJUSTMENT 5 – ANNUALIZE ADDITIONAL CUSTOMER REVENUE AND EXPENSES.

A. Adjustment 5 – Annualize Additional Customer Revenue and Expenses is a pro forma adjustment that adjusts revenues and expenses to recognize the number of customers served by the Eastern Group at the end of the test year; 29,236 customers. During the test year, the Eastern Group served an average of 28,636 customers, a difference of 600 customers. If the additional 600 customers being served at the end of the test year had taken service for the full year, revenues would have been $211,509 higher and expenses would have been $116,040 higher for the Eastern Group. The net effect of the increased revenues and increased expenses is $95,469.

Q. PLEASE EXPLAIN ADJUSTMENT 6 – PAYROLL EXPENSE ANNUALIZED.

A. Adjustment 6 – Payroll Expense Annualized is a pro forma adjustment to reflect pay rates in effect at the end of the test year for a full year. This adjustment is intended to recognize pay rate changes that occurred throughout the year as though they were in effect for the entire year. The adjustment to annualize payroll expense for the Eastern Group is $84,816.

Q. PLEASE EXPLAIN ADJUSTMENT 7 – PAYROLL TAX ANNUALIZED.

A. Adjustment 7 – Payroll Tax Annualized is a pro forma adjustment that adjusts payroll related taxes to correspond to the pro forma payroll expense annualized in Adjustment 6 – Payroll Expense Annualized. The 2002 federal unemployment tax rate of 6.2% and applicable base of the first $7,000 of employee wages have not changed from the 2001 levels. The 2002 state unemployment tax rate for the Company of .16% has changed from the 2001 tax rate of .17%, but the applicable wage base of $7,000 has remained in effect. The 2002 Medicare rate of 1.45% on all wages has not changed from the 2001 levels. The 2002 social security tax rate of 6.2% is the same as the 2001 rate, but the 2002 wage base limit has increased to $84,900 from the 2001 wage base limit of $80,400. The total pro forma payroll tax adjustment for the Eastern Group is an increase in expenses of $6,561.

Q. PLEASE EXPLAIN ADJUSTMENT 8 – PENSION.

A. Adjustment 8 – Pension is the pro forma adjustment that adjusts the Company's 401(k) expense to incorporate the pro forma payroll expense annualization adjustment discussed above. The 401(k) expense is based upon payroll expense. For the Eastern Group, the 401(k) expense adjustment is an increase of $7,499.

Q. PLEASE EXPLAIN ADJUSTMENT 9 – POWER AND WATER COSTS ANNUALIZED.

A. Adjustment 9 – Power and Water Costs Annualized is the pro forma adjustment to reflect the year-end power cost rates of all of the providers of purchased power and water to the Eastern Group applied to the test year consumption of both commodities for the individual systems.

Within the Eastern Group, only the San Manuel and Apache Junction systems purchase water. The Company purchases water for the San Manuel system from BHP Copper Company and for the Apache Junction system the Company purchases CAP water. In March 2002, BHP Copper Company increased its cost per thousand gallons from $0.60 to $1.12, a $0.52 increase or 87%. To annualize the effect of this increase in the cost to buy water from BHP Copper Company for the San Manuel system, a pro forma adjustment increasing the purchased water costs by $123,979 is necessary. Accordingly, the PWAM rate for the San Manuel system should be set to zero and the new base cost of purchased water will be $1.12 per thousand gallons. Since this level of purchased water expense is already being included in the San Manuel customers' water bills, the indicated increase in metered revenue overstates the impact on San Manuel customers by approximately 28 percent.

The Company purchases CAP water for the Apache Junction system from the CAWCD at rates that are adjusted annually. During June 2002, the Company received the final rate sheets for M&I charges and delivery charges that will be in effect beginning January 1, 2003. The M&I rate of $43 per acre-foot will not be changed, but the delivery rate of $58 per acre-foot will increase to $66 per acre-foot. CAWCD requires that payments for the monthly water order be made two months in advance of delivery. Therefore, the payment for the January water order based on the new $66 rate will be made in November. To reflect this increase in purchased CAP water costs and to include the effect of the Company's proposal to begin expensing the M&I charges requires a pro forma adjustment of $166,225 for the Apache Junction system.

The Company buys power for the Eastern Group from Arizona Public Service Company, Salt River Project, Sulphur Springs Valley Electric Cooperative, and the San Carlos Irrigation District. The Company's pro forma adjustment to reflect changes in the power cost rates for the Eastern Group is a reduction in power costs of $4,111. The PPAM rates for the affected systems should be reset to zero with recognition of the lower pro forma level of purchased power costs per gallon pumped for each respective system.

Q. MS. HUBBARD, ARE ANY OTHER PURCHASED WATER EXPENSES INCLUDED IN ADJUSTMENT 9 – POWER AND WATER COSTS ANNUALIZED?

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A. Yes. Adjustment 9 also includes a pro forma adjustment for the annual amortization necessary to charge the deferred M&I charges, both the pre-1991 M&I deferral and the post-1990 M&I deferral, to expense over a three-year period. The resulting annual amortization expense is $233,588.

Q. MS. HUBBARD, PLEASE EXPLAIN THE RATIONALE FOR THE SELECTION OF A THREE-YEAR AMORTIZATION PERIOD FOR THE RECOVERY OF THE DEFERRED M&I CHARGES.

A. The Company has selected a three-year recovery period to match the period of time between a decision in this proceeding and the anticipated filing of the next Eastern Group rate application. Because the Environmental Protection Agency has revised the maximum contaminant level for arsenic to 10 parts per billion, the Company will be required to implement new treatment procedures for its water systems. The compliance deadline is the end of January 2006 and while it is certainly possible that rate relief will be needed sooner, the Company anticipates filing a rate application upon completion of all treatment facilities inclusive of new operating expenses during 2006. If a decision in this proceeding is issued in 2003, that will effectively be a three-year period.

Q. IS THE COMPANY ANTICIPATING ANY ADDITIONAL INCREASES IN THE COST OF PURCHASING WATER FOR THE SAN MANUEL SYSTEM?

A. Yes. BHP Copper Company has ceased its mining operations and is concentrating on smelting which will have the effect of spreading its fixed costs of obtaining water over fewer users thereby increasing its unit cost of water. Although BHP Copper Company is phasing in this increase, water costs increased 87% on March 1, 2002 and another increase is likely as a result of

BHP Copper Company's June 30, 2002 results, which is the end of its fiscal year. The next increase will not become effective before January 1, 2003.

Q. PLEASE EXPLAIN ADJUSTMENT 10 – INSURANCE.

A. Adjustment 10 – Insurance is the pro forma adjustment necessary to reflect the changes in insurance premiums for life insurance, medical insurance, dental insurance, long-term disability insurance, worker's compensation insurance and liability insurance. The total increase in premiums from the 2001 levels that the Company will experience in the upcoming year for the Eastern Group is $71,202.

Q. PLEASE EXPLAIN ADJUSTMENT 11 – CHLORINATION COST ADJUSTMENT.

A. Adjustment 11 – Chlorination Cost Adjustment is the pro forma adjustment to annualize chlorination expenses resulting from changes to the chlorination program for the Eastern Group, as discussed by Mr. Garfield in his testimony. The adjustment increases operations and maintenance expenses by $134,260.

Q. PLEASE EXPLAIN ADJUSTMENT 12 – WATER TESTING ANNUALIZED.

A. Adjustment 12 – Water Testing Annualized is the pro forma adjustment to reflect the current level of water testing costs for the Eastern Group. This adjustment does not include water-testing costs billed by ADEQ under the MAP. Adjustment 4 above discusses the treatment of MAP testing costs in this proceeding.

The water testing costs that are annualized by this adjustment are costs associated with complying with the testing requirements for other constituents not included in the MAP, such as BACTI, Nitrates, Nickel, Sodium, Sulfate, and Radiochemicals. The Company has the responsibility of administering all of the required constituent tests for each of the Eastern Group systems not included in the MAP. These non-MAP testing costs were annualized by identifying the required number of tests for constituents not covered by the MAP. The resulting figure was multiplied by the required testing frequency and the most current actual cost of performing the tests. The pro forma adjustment for the non-MAP water testing expenses is an increase of $12,086 for the Eastern Group.

Q. **PLEASE EXPLAIN ADJUSTMENT 13 – OFFICE RENT AND CLEANING ANNUALIZED.**

A. Adjustment 13 – Office Rent and Cleaning Annualized is the pro forma adjustment to reflect the change in office rents and related expenses such as cleaning, trash removal, pest control and security. The 2001 level of expenditures for these expenses was compared to the estimated level of costs for 2002 based upon known and measurable monthly expenses resulting in an increase of $582 for the Eastern Group.

Q. **PLEASE EXPLAIN ADJUSTMENT 14 – PAPER, BILLING, POSTAGE ANNUALIZED.**

A. Adjustment 14 – Paper, Billing, Postage Annualized is the pro forma adjustment to reflect the changes in costs of printed billing documents and related envelopes. Printed billing documents include customer bills, delinquent notices, collection notices, and door hangers. In 2002, the Company will also be affected by an increase in United States Postal Service rates to mail billing documents. The effect on the Eastern Group for the changes in paper, billing and postage is an increase in expenses of $13,150.

Q. PLEASE EXPLAIN ADJUSTMENT 15 – TANK MAINTENANCE-INCREASE ANNUAL ACCRUAL.

A. Adjustment 15 – Tank Maintenance-Increase Annual Accrual is the pro forma adjustment to reflect the costs associated with the changes that the Company has adopted in its tank maintenance program, the benefits of which are more fully explained in the Direct Testimony of Mr. William M. Garfield. The effect of these changes on the Eastern Group is an increase in expense of $147,815.

Q. PLEASE EXPLAIN ADJUSTMENT 16 – AMORTIZATION OF 2001 RATE CASE EXPENSE.

A. Adjustment 16 – Amortization of 2001 Rate Case Expense is the pro forma adjustment that is necessary to include a portion of the costs to prepare and litigate this rate increase request for the Eastern Group. The Company is proposing to amortize the estimated rate case expenses of $257,550 over a three-year period resulting in a pro forma adjustment of $85,850 a year for three years.

Q. PLEASE EXPLAIN ADJUSTMENT 17 – SIX MONTHS ADDITIONAL DEPRECIATION EXPENSE.

A. Adjustment 17 – Six Months Additional Depreciation Expense is a pro forma adjustment to annualize depreciation expense to reflect a full year of depreciation expense on test year plant additions and retirements. Because the Company's depreciation policy utilizes a half-year convention on all plant additions and retirements, the test year depreciation expense only includes depreciation expense on test year additions and retirements for six months. To recognize a full twelve months of depreciation expense on the test year plant additions and retirements, a pro forma adjustment has been computed. The adjustment to annualize the depreciation expense for the Eastern Group is $80,581.

Q. MS. HUBBARD, DOES THE PRO FORMA ADJUSTMENT TO ANNUALIZE DEPRECIATION EXPENSE INCORPORATE THE EFFECTS OF USING COMPONENT DEPRECIATION RATES AS ORDERED IN DECISION NO. 64282 (DECEMBER 28, 2001)?

A. Yes, component depreciation rates have been used to develop the adjusted test year depreciation expense. The rates were developed in the Company's last depreciation study as authorized in Decision No. 58120 and formed the basis of the composite rate of 2.59 percent that was used in that test year. The conversion to the use of individual depreciation accounts is discussed in Mr. Kennedy's testimony.

Q. PLEASE EXPLAIN ADJUSTMENT 18 – DEPRECIATION EXPENSE-COMPLETED CONSTRUCTION.

A. Adjustment 18 – Depreciation Expense Completed Construction is a pro forma adjustment to depreciation expense to reflect additional depreciation on revenue-neutral construction that will be completed and placed in service within the twelve months immediately following the end of the test year. This plant, intended to serve test year customers, will be in service prior to the implementation of the new rates that will result from this proceeding. The effect of the additional depreciation is an increase in expense of $172,296 for the Eastern Group.

Q. PLEASE EXPLAIN ADJUSTMENT 19 – PROPERTY TAXES ANNUALIZED.

A. Adjustment 19 – Property Taxes Annualized is a pro forma adjustment to test year property taxes to reflect known and measurable changes in plant and revenues as reflected in this rate application. The pro forma adjustment utilizes the current methodology used by the Arizona Department of Revenue to determine what is referred to as full cash value for each of the Company's systems. It is also the same methodology adopted in Decision No. 64282 for the Company's Northern Group water systems. The resulting adjustment to the property tax expenses for the Eastern Group is an increase of $151,399.

Q. PLEASE EXPLAIN ADJUSTMENT 20 – VEHICLE AND EQUIPMENT LEASE COSTS.

A. Adjustment 20 – Vehicle And Equipment Lease Costs is a pro forma adjustment to the test year level of vehicle and equipment lease costs to annualize the cost of leased vehicles and equipment that were added during 2001. The effect of this adjustment is an increase in expense of $7,446 for the Eastern Group.

Q. PLEASE EXPLAIN ADJUSTMENT 21 - FEDERAL INCOME TAX.

A. Adjustment 21 – Federal Income Tax is a pro forma adjustment to reflect the federal income tax effect of the pro forma adjustments included on Schedule C-2.

Q. PLEASE EXPLAIN ADJUSTMENT 22 – STATE INCOME TAX.

A. Adjustment 22 – State Income Tax is a pro forma adjustment to reflect the state income tax effect of the pro forma adjustments included on Schedule C-2.

Q. PLEASE EXPLAIN ADJUSTMENT 23 – TAX EFFECT OF INTEREST SYNCHRONIZATION.

A. For ratemaking purposes, a utility's revenue requirement reflects the recovery of a certain level of interest expense. It is this interest expense that should be reflected as the interest deduction for purposes of calculating the tax expense. The Tax Effect of Interest Synchronization adjustment computed on Adjustment 23 is necessary to match the rate base used in determining revenue requirements with the proportionate part of the total amount of debt and equity used to determine the cost of capital. The amount of interest expense that customers of each system in the Eastern Group contribute through payment of water rates should be the same as the amount of interest expense deducted from revenues in calculating each system's tax expense. Synchronizing the interest deduction for ratemaking with the interest deduction for earnings purposes as reflected in Adjustment 23 accomplishes this goal.

Q. PLEASE EXPLAIN SCHEDULE C-3.

A. Schedule C-3 titled "Computation of Gross Revenue Conversion Factor" shows the development of the Gross Revenue Conversion Factor. The Gross Revenue Conversion Factor used by the Company is 1.63241 for the test year 2001. The revenue conversion factor is used to gross up an income requirement to a revenue requirement or, simply stated, it takes revenue in excess of one dollar to generate one dollar of income due to factors such as taxes imposed on revenues. For the Company, the gross revenue conversion factor recognizes the effective federal income tax rate of 31.55744% and the effective state income tax rate of 6.95183% and a bad debt factor of .2316% to generate a revenue multiplier of 1.63241.

VIII. Company's Financial Statements

Q. RULE R14-2-103 OF THE ACC'S RATE APPLICATION FILING REQUIREMENTS REQUIRES THE FILING OF FINANCIAL STATEMENTS AND STATISTICAL SCHEDULES. MS. HUBBARD, IS IT PART OF YOUR TESTIMONY TO SPONSOR THE E-SERIES OF SCHEDULES?

A. Yes, it is part of my testimony in this proceeding to present the E-Series of schedules required by the ACC's rules related to rate application filing requirements.

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF THE E-SERIES SCHEDULES THAT YOU ARE SPONSORING IN THIS PROCEEDING.

A. Schedule E-1 titled "Comparative Balance Sheets-Total Company-Prior Years 1999 & 2000 and Test Year 2001" sets forth the balance sheets of the Company as of the end of years 1999, 2000, and 2001. Schedule E-2 titled, "Comparative Income Statements-Total Company and Eastern Group-Prior Years 1999 & 2000 and Test Year 2001" is the income statements of the Company for the years 1999, 2000, and 2001. Schedule E-3 titled "Comparative Statement of Cash Flows-Total Company- Test Year 2001 and Prior Years 2000 & 1999" presents the statements of cash flows of the Company for the years 1999, 2000, and 2001. Schedule E-4 titled "Statement of Changes in Stockholder's Equity-Total Company- Prior Years 1999 & 2000 and Test Year 2001" shows changes in the stockholder's equity components since January 1, 1999 to the end of the test year. Schedule E-5 titled "Detail of Utility Plant at End of Prior Year 2000 and Test Year 2001" is a four-page schedule that provides a summary of changes in the plant balances on a plant accounting basis for the Eastern Group systems for the test year. Schedule E-6 titled "Comparative Operating Income Statements-Test Year 2001 and Prior Years 2000 & 1999" is a three-page schedule that presents operating income statements for each of the Eastern Group systems for the years 1999, 2000, and 2001. Schedule E-7 titled "Operating Statistics-Test Year 2001 and Prior Years 2000 & 1999" is a three-page schedule that sets forth the Eastern Group's statistics based upon sales quantities and customer information for the years 1999, 2000, and 2001. Schedule E-8 titled "Taxes Charged to Operations-Test Year 2001 and Prior Years 2000 & 1999" is a three-page schedule that provides details regarding taxes incurred by the Company for the years 1999, 2000, and 2001.

Q. **MS. HUBBARD, PLEASE TURN YOUR ATTENTION TO THE F-SERIES OF SCHEDULES IN YOUR EXHIBITS. ARE YOU SPONSORING THE F-SERIES OF SCHEDULES ALSO?**

A. Yes, I am sponsoring the F-Series of schedules.

Q. **PLEASE PROVIDE A BRIEF OVERVIEW OF THE F-SERIES SCHEDULES THAT YOU ARE SPONSORING IN THIS PROCEEDING.**

A. The F-Series of schedules in the ACC's rate application filing requirements are labeled "Projections and Forecasts". As such, the F-Series of schedules provide a comparison of current results of operations using different assumptions to project future operating results. More specifically, Schedule F-1 titled "Projected Income Statements-Eastern Group-Test Year 2001 and Projected Year 2002" forecasts 2002 income using the Eastern Group's billing determinants and the proposed rate design. Schedule F-1 has been prepared for the Eastern Group for this proceeding. Schedule F-2 titled, "Statement of Cash Flows-Present and Proposed Rates-Total Company-Test Year 2001 and Projected Year 2002" has only been prepared for the test year 2001 because the projected data has not been prepared on a Total Company basis. Schedule F-3 titled "Projected Construction Requirements –Test Year 2001 and Projected Years 2002, 2003 & 2004" shows the Company's projected construction expenditures for the years 2002, 2003, and 2004 for the Eastern Group. This schedule details the total construction expenditures shown on Schedule A-4 segregated on a functional basis: production plant, water treatment plant, transmission and distribution plant, and general plant. Schedule F-4 titled "Assumptions Used in Developing Projections – Eastern Group – Projected Year 2002" provides a general description of the assumptions used in developing projections for 2002 with respect to customer growth, customer water demand, changes in expenses and construction requirements.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

ARIZONA WATER COMPANY

Docket No. W-1445A-02-0619

2002 RATE HEARING EXHIBIT NO. ___

For Test Year Ending 12/31/01

PREPARED

DIRECT TESTIMONY & EXHIBITS

OF

Ralph J. Kennedy

EXHIBIT

A-15

~~Admitted~~

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ARIZONA WATER COMPANY

Direct Testimony of

Ralph J. Kennedy

Q. WHAT IS YOUR NAME, EMPLOYER AND OCCUPATION?

A. My name is Ralph J. Kennedy. I am employed by Arizona Water Company as Vice President and Treasurer.

Q. PLEASE DESCRIBE YOUR WORK EXPERIENCE AND EDUCATIONAL BACKGROUND.

A. I was employed by the Arizona Water Company in January 1987 as Vice President and Treasurer. My previous regulatory experience was as Chief of the Accounting and Rates section of the Arizona Corporation Commission ("ACC") from 1985 to 1986 and as Manager of Accounts and Finance for the Illinois Commerce Commission from 1974 to 1978. In addition to my regulatory work, I have also been employed as a management consultant with the firm of Booz, Allen & Hamilton, as Assistant to the Illinois Director of Revenue and as a programmer analyst. I have also been self-employed as an independent trader on the Chicago Board Options Exchange and as a consultant on government accounting system and controls.

I completed my undergraduate work at the University of Illinois – Chicago and received a B.S. with an accounting concentration. I continued my education at the University of Chicago where I earned an M.B.A. with a major in accounting and behavioral science. I am a C.P.A. in Illinois and Arizona and a member of both the Arizona Society of Certified Public Accountants and the American Institute of Certified Public Accountants.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to provide an overview of the filing, propose an arsenic cost recovery mechanism for the Eastern Group, discuss consolidation of the Apache Junction and Superior systems, recommend the weighted cost of capital, address the change in depreciation methodology required by Decision No. 64282, propose new rates that will satisfy the revenue requirement and discuss the effects of the proposed tariffs on customer bills.

I. Overview Of Filing

Q. PLEASE DESCRIBE THE EASTERN GROUP RATE FILING.

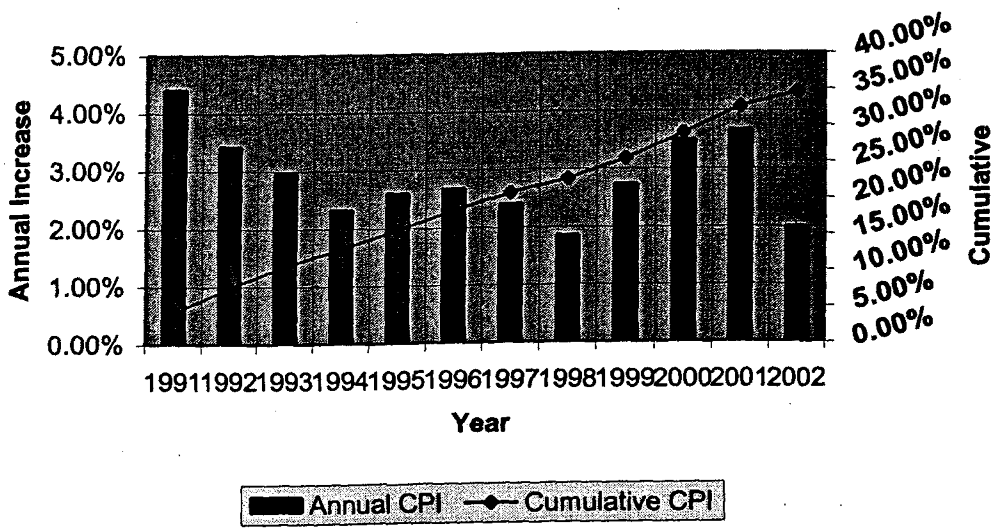
A. The Company filed an application with the ACC to adjust its rates and charges for its Eastern Group water systems based on operating results and investment in the water systems for the adjusted test year of 2001. As of December 31, 2001 the Eastern Group currently includes eight systems serving over 29,000 customers as shown in Table 1:

Table 1

		Customers	Percent
1.	Apache Junction	16,093	55.0%
2.	Superior	1,288	4.4%
3.	Bisbee	3,393	11.6%
4.	Sierra Vista	2,294	7.8%
5.	Miami	3,027	10.4%
6.	San Manuel	1,552	5.3%
7.	Oracle	1,401	4.8%
8.	Winkelman	188	0.6%
Total Eastern Group		**29,236**	**100.0%**

Apache Junction, located on the growing eastern edge of the Phoenix metropolitan area, is the Eastern Group's largest system. The other seven systems range from 188 to 3,393 customers. These seven systems average only 1,643 customers and have low to negative growth. The current outdated rates became effective in January 1993, but were based on operating results and investment for test year 1990.

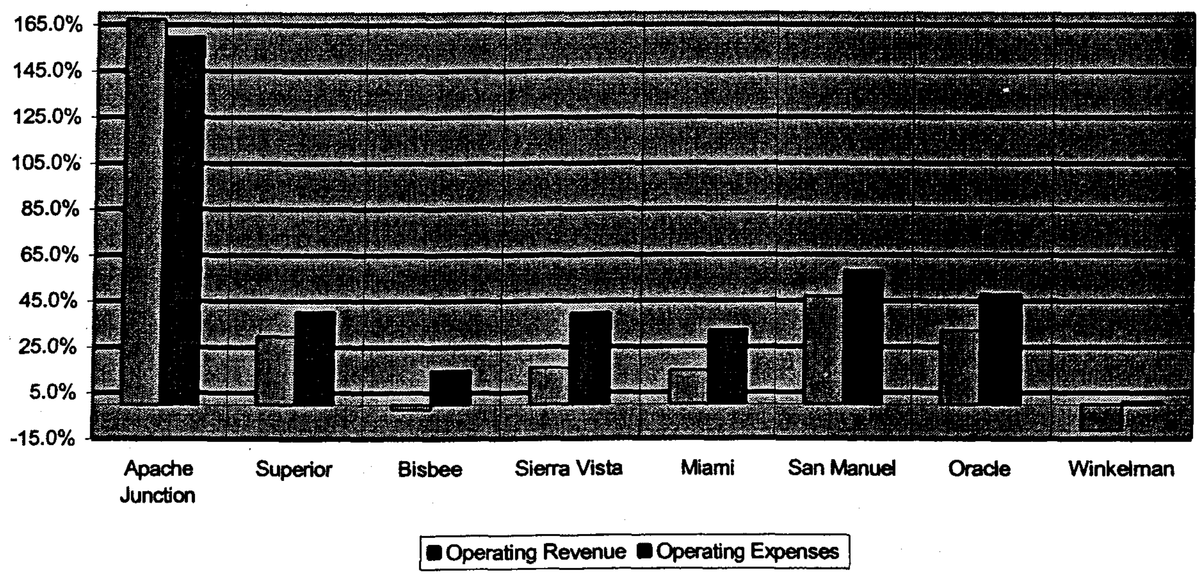
Annual & Cumulative Increase In CPI - 1990 Through 5/30/2002



There have been numerous changes in the economy and the Company's operations since 1990. Although annual inflation rates have been more moderate in the 1990's than in the 1980's, the above chart demonstrates that the cost of living has increased 35% over the period from 1990 through May 2002.

Since 1990, the general costs of doing business, such as salaries, supplies, insurance, and purchased water costs have increased significantly. The local economies of several service areas have suffered due to reduced operations or shutdowns by major employers, which has reduced water sales both directly and indirectly. Regulatory changes, such as the amendments to the Safe Drinking Water Act that have required increased water testing, treatment, and consumer reporting, have further aggravated the impact of increasing price levels on the Company's operating expenses. As the following chart demonstrates, in seven of the eight Eastern Group systems, the growth in revenue has been surpassed by the growth in expenses. Moreover, in Bisbee and Winkelman the 2001 revenue was actually **less** than the 1990 revenue.

Comparative Change In Operating Revenue & Expense
1990 To 2001 Actual



The revenues based on the test year 1990 rates are inadequate to cover the current cost of service and provide a reasonable rate of return on the Company's increased investment in water system facilities. Looking ahead, the existing rates are inadequate to even maintain the Company's financial viability. Since 1990, the Company's net investment in additional water storage tanks, water mains, wells, increased pressure boosting capacity, back-up power supplies, chlorination equipment and other facilities for the Eastern Group systems has increased 70% from $20 million to $34 million. This $14 million increase occurred over 11 years, at a rate of approximately $1.3 million per year.

In contrast, over the next 3 years the Eastern Group's arsenic compliance capital costs alone are estimated to be over $12 million. This $4 million annual rate of investment is on top of other required investments necessary to maintain adequate service to existing customers. The Company will have to more than double its long-term debt over the next three years to be able to finance the $30 million Company-wide arsenic capital costs.

Complying with the EPA's new arsenic maximum contaminant level ("MCL") of 10 parts per billion ("PPB") by January 2006 will strain the Company's financing ability. The rates set in this proceeding will become effective in late 2003 based on test year 2001. The level of these rates and the provisions enabling the Company to recover the future costs of complying with the 10 PPB arsenic MCL without a formal rate proceeding will be decisive factors determining whether or not the Company can finance both its obligatory system improvements and the mandated arsenic treatment facilities over the 2003 to 2005 time frame.

The Company is requesting an overall 29.5% increase in Eastern Group revenues to recover the increased costs of providing service and allow the Company an opportunity to earn a reasonable rate of return on its required investment in water utility plant.

II. Recovery of Arsenic Treatment Costs

Q. HOW WILL THE MANDATORY ARSENIC TREATMENT FACILITIES IMPACT THE COMPANY?

A. The Company will need to design, finance, construct and operate as many as fifty (50) arsenic water treatment facilities company-wide. These facilities will provide a combined total treatment capacity of 60.65 million gallons per day ("MGD"). In the Eastern Group, there will be as many as twenty-one (21) water treatment plants with a combined treatment capacity of 23 MGD required to comply with the new arsenic MCL. Mr. Garfield testified, in the Company's September 2000 study for the EPA, that the total arsenic capital costs for the Eastern Group were estimated at $12.5 million. These costs are in addition to the needs of the Company's normal, on-going construction program.

Q. WHAT WILL THE RATE IMPACT OF THE NEW ARSENIC MCL BE ON THE COMPANY'S EASTERN GROUP CUSTOMERS?

A. In a more recent arsenic study, Mr. Whitehead has estimated that the total Eastern Group capital costs will be $12 million for existing sources of supply. The costs of arsenic treatment do not uniformly impact all customers. Customers in Bisbee, Sierra Vista, Miami, Oracle and Winkelman will not be faced directly with the costs of arsenic treatment requirements, given the quality of their current water sources. The other three Eastern Group systems, however, will be faced with varying capital costs that will increase those systems' adjusted rate bases from 36% to as much as 198%, as Table 2 indicates.

Table 2

	Adjusted Rate Base	Customers	Rate Base/C	Arsenic Plant Facilities Increase	Arsenic Plant Facilities Percent
Apache Junction	$ 24,207,015	15,353	1,577	$ 8,795,180	36.3%
Superior	2,673,576	1,286	2,079	1,682,813	62.9%
San Manuel	793,994	1,555	511	1,575,000	198.4%
Group Total	**$ 27,674,585**	**18,194**		**$ 12,052,993**	

These three systems will also be faced with significant increases in operation and maintenance expenses for arsenic treatment and disposal. The annual costs have been estimated at $2.6 million by Mr. Garfield.

Unfortunately, the need for an extremely large infusion of capital to finance the mandatory arsenic treatment program will be occurring simultaneously throughout the water industry, with the strongest demands arising in the southwestern United States. The insurance companies, who are normally interested in purchasing the Company's general mortgage bonds, may be less interested in financings that are required primarily for arsenic treatment facilities. When the demand for funds and the risk of the borrower's operations increase, it becomes more difficult to find financing at any cost. The ACC's responsibility to maintain the financial and operating viability of the water companies it regulates during these trying times will require innovative measures.

Q. HAS THE ACC INDICATED A WILLINGNESS TO CONSIDER SPECIAL ARSENIC COST RECOVERY PROCEDURES?

A. Yes. In Decision No. 64282, the recent rate order for the Company's Northern Group systems issued in December 2001, a second phase of the case was authorized to consider arsenic cost recovery and the issue of rate consolidation.

Q. WHAT IS THE STATUS OF THE PHASE II PROCEEDINGS DEALING WITH ARSENIC COST RECOVERY?

A. The Company, Staff and RUCO have held a number of meetings to consider various cost recovery approaches. The Company initially proposed an advice letter procedure whereby rates could be adjusted for the increased capital and O&M operating costs of completed arsenic treatment facilities. This approach was based on procedures that are currently in use in other states for regulated water utilities. Staff and RUCO did not support this approach and expressed concerns both about its legality in Arizona and their ability to deal with the numerous filings that would have been permitted given their small Staff size.

The Company then proposed a step increase procedure based on an approach that had been successfully used by Arizona Public Service Company and upheld by the Arizona Supreme Court *(Arizona Community Action Association v. Arizona Corporation Commission, 123 Ariz. 228, 559 P.2d 184 (1979))*. In a series of meetings with Staff and RUCO, the step increase procedure was developed to a point of general agreement and a Joint Report was filed on May 30, 2002. On July 16, 2002, a Procedural Conference was held to address the steps needed to resolve the remaining disagreements and finalize recommendations to the Commission on an arsenic cost recovery methodology and the Company's proposed rate consolidation. A public hearing on these questions is scheduled for October 3 after the Company and Staff and RUCO submit testimony and exhibits on August 23 and September 23, respectively.

Q. WHY IS THE ISSUE OF RATE CONSOLIDATION BEING CONSIDERED ALONG WITH ARSENIC COST RECOVERY?

A. There are several overlapping considerations that make rate consolidation a compelling policy alternative for relieving the rate impact of mandatory arsenic treatment costs on the customers of small systems burdened with high-arsenic sources of supplies. Although high concentrations of arsenic are naturally present in groundwater throughout the southwest, it is not uniformly distributed throughout Arizona or even the Company's various systems. Some systems have high concentrations of arsenic in existing drinking water supplies while other systems have levels below the new MCL of 10 PPB. Nevertheless, meeting the new arsenic MCL by January 2006 will be a state-wide problem and will require a consolidated state-wide approach if it is to be resolved to the satisfaction of all interested parties.

The high capital and operating costs of arsenic treatment become especially burdensome when they must be recouped over a small customer base. Table 2 (page 6) showing the estimated Eastern Group arsenic treatment capital costs illustrates the problem. In the Superior and San Manuel systems, the required arsenic capital costs increase rate base by 63% and 198%, respectively.

In San Manuel, the incremental increase in the revenue requirement for arsenic capital costs and treatment is estimated to be between 124% and 133% as computed on Exhibit RJK-1. Assigning the capital costs to the minimum charge and the O&M costs to the commodity charge produces the following incremental arsenic increase range:

Minimum 5/8"	$14.99 to $19.92
Commodity	$ 1.04 to $ 1.56

In Superior, the incremental increase in the revenue requirement for arsenic capital costs and treatment is estimated to be between 47% and 85% as computed on Exhibit RJK-1. Assigning the capital costs to the minimum charge and the O&M costs to the commodity charge produces the following incremental arsenic increase range:

Minimum 5/8"	$17.42 to $26.04
Commodity	$ 0.51 to $ 1.65

III. APACHE JUNCTION AND SUPERIOR SYSTEM CONSOLIDATION

Q. WHY IS THE COMPANY PROPOSING THIS CONSOLIDATION?

A. The Apache Junction system is growing eastward at a rapid pace. New developments are currently underway in the Florence Junction area and are likely to move into the western portion of the Superior CCN during the next real estate cycle. Interconnection of these two systems will provide operating benefits and increased reliability for customers of both systems as explained by Mr. Whitehead, Vice President of Engineering, in his direct testimony.

Q. IS THE COMPANY PROPOSING A SINGLE-TARIFF RATE STRUCTURE FOR THE CONSOLIDATED APACHE JUNCTION AND SUPERIOR SYSTEMS?

A. Not at this time. Although the systems will be combined for accounting purposes and physically interconnected, at this time the Company is proposing only a partial rate consolidation. It is the first of a two-step proposal.

Q. WHEN WILL THE ACCOUNTING CONSOLIDATION TAKE PLACE?

A. The accounting consolidation will take place on January 1, 2004 following the ACC decision in this proceeding. However, the existing Apache Junction and Superior billing districts will be maintained and customers will be billed at the rates authorized in this proceeding

Q. WHY ISN'T FULL RATE CONSOLIDATION BEING PROPOSED AT THIS TIME?

A. Full rate consolidation at this time would produce an overall decrease in Superior's total metered revenue because both the consolidated minimum and commodity charges would be less than Superior's current minimum and commodity charges. On a stand-alone basis Superior would require a 71% increase, while under full consolidated rates Superior revenues would decrease by 16%.

Q. PLEASE DESCRIBE THE FIRST RATE CONSOLIDATION STEP THAT IS BEING PROPOSED.

A. The first proposed step toward rate consolidation establishes a common minimum charge for both systems. However, until the next Eastern Group rate case, each system will continue to have a unique commodity charge. Superior's **current** commodity charge is 61% greater than Apache Junction's **proposed** commodity charge. Under the first step of this proposal, Superior's 5/8" minimum and commodity charges will not change, yet metered revenues will increase 9% due to elimination of 1,000 gallons in the minimum charge and the realignment of minimum charges toward the theoretical meter multiples. The second step will take place as part of the next Eastern Group rate case filing when a common commodity charge will be proposed for all Superior and Apache Junction customers.

IV. WEIGHTED COST OF CAPITAL

Q. HOW IS THE WEIGHTED COST OF CAPITAL DETERMINED?

A. The weighted cost of capital is determined by establishing the cost of the individual capital components and then calculating an overall cost weighted by each component's percent of the total capital structure and individual cost. The Company's capital structure includes three components: Short-Term Debt, Long-Term Debt and Common Stock Equity.

Q. WHAT IS THE COST OF THE INDIVIDUAL COMPONENTS OF THE CAPITAL STRUCTURE?

A. The cost of Short-Term Debt and Long-Term Debt is set forth on Schedule D-2. Long-Term Debt costs are shown on lines 1 through 15. The Company's general mortgage bonds are listed by series with the annual interest and amortization on lines 1 through 8. The Company's computation of its Long-Term Debt cost shown on lines 9 through 15 is the approach adopted by the ACC in the Company's last two general rate cases and the method used by the Company in this proceeding. This method relies on an unchanging cost for each debt issue and then weights the cost of each individual issue by its percentage of the total debt outstanding.

In summary, at the end of adjusted test year 2001, the Company had total Long-Term Debt of $23,000,677 at a weighted average embedded cost of 8.4557 percent. The schedule also shows that at the end of projected year 2002, the cost rate on Long-Term Debt is expected to decrease slightly to 8.441 percent because of principal repayments during the year on the Series I bonds.

In addition, at the end of adjusted test year 2001, the Company had a short-term debt total of $2,850,000. The computation of the cost of Short-Term Debt is presented on lines 16 through line 20. The daily balance of Short-Term debt outstanding is continually fluctuating. The rate also changes during the year. During the test year, weighted average short-term interest cost as shown on line 20 was 7.37 percent.

Q. HOW DID YOU DETERMINE THE COST OF COMMON EQUITY?

A. The cost of common equity was determined by Company witness Dr. Thomas Zepp. I have used his cost rate in computing the overall weighted cost of capital.

Q. PLEASE EXPLAIN HOW YOU COMPUTED THE OVERALL WEIGHTED COST OF CAPITAL ONCE YOU DETERMINED THE COST OF THE INDIVIDUAL COMPONENTS.

A. Schedule D-1, entitled "Summary Cost of Capital"," sets forth the capital structure of the Company on lines 1 through 4 at the end of test year 2001, adjusted test year 2001 and the end of projected year 2002. It shows the components of the capital structure, the percent each item of capital bears to the total, the cost rate determined for each component of capital and the weighted composite cost for each component. The weighted composite cost of each component is added to arrive at the overall weighted composite cost on line 4 of 11.00% for adjusted test year 2001.

Underneath the Total Company data, similar information is presented on lines 5 through 8 for the Eastern Group. The total capital amounts shown on Line 8 for End Of Test Year 2001 match the TY2001 unadjusted rate base from Schedule B-2 plus the allocated (three factor) Phoenix Office & Meter Shop. The Adjusted Test Year 2001 total capital is the capital structure necessary to support the adjusted test year 2001 OCLD rate base of $ 41,604,880 shown on Schedule B-1.

In accordance with ACC requirements, this schedule also includes an analysis of the cost of capital of the Company at the end of projected year 2002. The End Of Projected Year 2002 total capital is based on the ratio of the Adjusted Test Year 2001 Eastern Group total capital amount on line 8 to the Total Company amount on line 4. The Company forecasts total invested capital in the Eastern Group will be $45,172, 595.

Q. MR. KENNEDY, DO YOU HAVE AN OPINION AS TO WHAT WOULD BE A FAIR AND PROPER RATE OF RETURN FOR ARIZONA WATER COMPANY TO EARN ON ITS ADJUSTED OCLD RATE BASE?

A. Yes, I do. It should be 11.0 percent, the weighted composite cost of capital computed on Schedule D-1.

V. <u>DEPRECIATION METHODOLOGY</u>

Q. DECISION NO. 64282 CONCLUDED THAT THE COMPANY SHOULD FILE A SCHEDULE OF COMPONENT DEPRECIATION RATES FOR ALL OF ITS SYSTEMS IN ITS NEXT RATE APPLICATION. HAS THE COMPANY DONE SO?

A. The Company submits the following schedule of component depreciation rates for all of its systems:

Plant Account		
Number	Description	Component Depreciation
314	WELLS	3.33%
321	PUMPING PLANT STRUCTURES & IMPROVEMENTS	2.86%
325	ELECTRIC PUMPING EQUIPMENT	5.00%
328	GAS ENGINE EQUIPMENT	4.00%
331	WATER TREATMENT STRUCTURES & IMPROVEMENTS	2.50%
332	WATER TREATMENT EQUIPMENT	2.86%
341	TRANSMISSION & DISTRIBUTION STRUCTURES	3.33%
342	STORAGE TANKS	1.82%
343	TRANSMISSION & DISTRIBUTION MAINS	1.79%
344	FIRE SPRINKLER TAPS	2.00%
345	SERVICES	2.63%
346	METERS	3.85%
348	HYDRANTS	1.79%
390	GENERAL PLANT STRUCTURES	2.50%
391	OFFICE FURNITURE & EQUIPMENT	6.67%
393	WAREHOUSE EQUIPMENT	5.00%
394	TOOLS, SHOP & GARAGE EQUIPMENT	3.33%
395	LABORATORY EQUIPMENT	5.00%
396	POWER OPERATED EQUIPMENT	6.67%
397	COMMUNICATION EQUIPMENT	6.67%
398	MISCELLANEOUS EQUIPMENT	3.33%

These component depreciation rates will be implemented prospectively based on discussions with ACC Utilities Division Staff. The pro forma depreciation expense adjustments for the Eastern Group described in Ms. Hubbard's testimony are based on the component depreciation rates rather than the presently authorized composite rate of 2.59%.

VI. Rate Design

Q. BEFORE ADDRESSING THE COMPANY'S PROPOSED TARIFF SCHEDULES, PLEASE EXPLAIN WHY THE COMPANY HAS NOT SUBMITTED ANY OF THE G SCHEDULES.

A. The G schedules pertain to the cost of service. These schedules have been omitted from this filing because the Company does not charge different rates to different classes of customers. Instead, the Company has a monthly minimum charge, which is based on meter size rather than on the type of customer receiving the service, and a single commodity charge for all gallons provided. Thus, the Company does not distinguish between residential, commercial, industrial and other classes of customers. Under these circumstances, a traditional cost of service analysis would provide little assistance in designing rates. In the procedural order, issued on August 1, 1995, in Docket No. U-1445-91-227, the ACC's Chief Administrative Law Judge indicated that the Company does not need to file a cost of service study (G schedules) if the Company does not intend to charge different rates to different classes of customers. In the recently concluded Northern Group rate case, Decision No. 64282 (December 28, 2001) a cost of service study was not required. In this case, the Company is not proposing to deviate from its historic practice and, therefore, a cost of service study is not required.

Q. WOULD YOU NOW DIRECT YOUR ATTENTION TO SCHEDULE H-1 AND EXPLAIN THAT SCHEDULE.

A. This schedule shows the revenue billed under present rates and the amount that would be generated by the proposed increase in metered water rates. No change in tariffs for public fire hydrants, miscellaneous, rents, or service establishment charges is being proposed.

Q. MR. KENNEDY, WOULD YOU NOW DIRECT YOUR ATTENTION TO PAGE 1 OF SCHEDULE H-2 AND SUMMARIZE THAT SCHEDULE?

A. This schedule is an analysis of revenue at present and proposed rates by meter size. It also indicates the proposed revenue increase by meter size in dollar amount and percentage. The average number of customers derived from the bill count is also shown by meter size and in total. The general service tariffs, pursuant to which we provide water service, do not differentiate between residential, commercial, and industrial customers. The tariffs only vary by meter size. These classifications are combined under the general classification of metered service.

Q. **PLEASE TURN TO SCHEDULE H-3 AND DESCRIBE THAT SCHEDULE.**

A. This schedule presents a comparison of present and proposed general service tariffs and proposed changes. It shows the existing minimum charges by meter size, the number of gallons included in the minimum charges and the present and proposed commodity cost.

The main purpose of the schedule is to provide a summary comparison of the Company's present and proposed rates as they relate to minimum charges for various size meters and the cost of water per 100 gallons.

Q. **MR. KENNEDY, WILL YOU NOW DIRECT YOUR ATTENTION TO SCHEDULE H-4 AND BRIEFLY EXPLAIN THAT SCHEDULE?**

A. This is a bill analysis for the 5/8-inch meter rate comparing present rates, proposed rates and the mathematical calculation of the percentage increase at various consumption levels from zero through 25,000 gallons.

Using Apache Junction as an example, you will note the average residential consumption in gallons per bill is shown on line 19. In Apache Junction, a 5/8-inch meter had an average consumption of 9,700 gallons. Under the present rates, the customer using that amount of water would be billed $34.78 and under the Company's proposed rate the customer using the same amount of water would be billed $42.62 an increase of 22.5 percent. The same illustration and comments would be applicable to the other systems. It is a mathematical computation of present and proposed rates for the 5/8-inch meter at various levels of consumption.

Q. **WHAT IS SCHEDULE H-5?**

A. This is a separately bound set of billing determinants for each system, commonly referred to as a "Bill Count".

Q. **WOULD YOU NOW TURN TO SCHEDULE H-6 AND EXPLAIN THAT SCHEDULE.**

A. This schedule is representative of our existing general service water rate and indicates the change in the minimum and commodity charges.

Q. **TURNING NOW TO SCHEDULE H-7, WOULD YOU PLEASE EXPLAIN THIS SCHEDULE?**

A. This is a proposed coin machine service tariff (CM-257) that is being revised to reflect the proposed rate for the Apache Junction system. This tariff is necessary for small bulk sales to people who haul water in lieu of having a meter set at their residence. The tariff specifies the number of gallons that the customer will receive for each quarter ($0.25) deposited. The number of gallons dispensed is based on the commodity cost plus relevant taxes.

Q. **NOW PLEASE TURN TO AND EXPLAIN SCHEDULE H-8.**

A. This schedule is a revised service charge tariff, which extends the service charges approved for the Northern Group systems in Decision No. 64282 to the Eastern Group systems.

Q. PLEASE REFER TO SCHEDULE H-9 AND EXPLAIN THAT SCHEDULE.

A. The service charges originally approved in Decision No. 58120 applied to all Company systems. This revised service charge tariff reflects the fact that the original service charges will now only apply to the five systems in the Western Group.

NOW TURN TO AND EXPLAIN SCHEDULE H-10.

A. This schedule identifies the existing tariff schedules for which the Company is not proposing any changes.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY IN THIS MATTER, MR. KENNEDY?

A. Yes, it does.

EXHIBITS

ARIZONA WATER COMPANY

Estimated Incremental Revenue Requirements of Arsenic Treatment To Meet EPA Standard of 10 PPB - San Manuel

RJK-1

Assumptions:	Low	Point	High
Capital Cost Range	1,410,000	1,480,522	1,551,044
O & M Cost	335,000	278,699	222,397
Allowed Return On Rate base	9.00%	9.64%	11.50%
Depreciation Rate - Treatment Plant		2.86%	
RR Property Taxes / Net Plant		2.08%	
Tax Conversion Factor		1.65	

	Amount	Amount	Amount
Treatment Plant & Related Facilities	**1,410,000**	**1,480,522**	**1,551,044**
Operating Revenue Required	**614,081**	**571,738**	**593,376**
Operating Expenses			
Depreciation	40,326	42,343	44,360
Property Taxes	29,370	30,839	32,308
O & M Treatment Expenses	335,000	278,699	222,397
Subtotal	404,696	351,881	299,065
Pre-tax Operating Income	209,385	219,858	294,311
Income Taxes	82,477	86,602	115,929
Total Operating Expenses	**487,173**	**438,483**	**414,994**
Net Operating Income	**126,900**	**133,247**	**178,370**
Required Return	126,908	133,256	178,382
Revenue Requirements			
Gross Return	209,385	219,858	294,311
Pre-tax Operating Expenses	404,696	351,881	299,065
Total	614,081	571,738	593,376
Actual 2001 Metered Revenue	$ 463,025	$ 463,025	$ 463,025
Customers @ 12/31/01	**1,552**	**1,552**	**1,552**
M/Gallons Sold 2001	**214,846**	**214,846**	**214,846**
Metered Revenue Per Customer	**$ 298.34**	**$ 298.34**	**$ 298.34**
Required Increase Per Customer	**$ 395.67**	**$ 368.39**	**$ 382.33**
Required Percentage Increase	**132.6%**	**123.5%**	**128.2%**
Required Increase Split Between Commodity & Minimum			
Commodity - O&M Treatment Expenses	**$ 1.56**	**$ 1.30**	**$ 1.04**
Monthly Minimum - Fixed Capital Costs	**$ 14.99**	**$ 15.73**	**$ 19.92**

ARIZONA WATER COMPANY

Docket No. W-1445A-02-0619

2002 RATE HEARING EXHIBIT NO. ___

For Test Year Ending 12/31/01

PREPARED

DIRECT TESTIMONY & EXHIBITS

OF

Michael J. Whitehead

EXHIBIT

A-9

~~Admitted~~

TABLE OF CONTENTS

ARIZONA WATER COMPANY

Direct Testimony of

MICHAEL J. WHITEHEAD

I. <u>Introduction and Qualifications</u>

Q. WHAT IS YOUR NAME, EMPLOYER AND OCCUPATION?

A. My name is Michael J. Whitehead. I am employed by Arizona Water Company (the "Company") as Vice President – Engineering..

Q. PLEASE DESCRIBE YOUR WORK EXPERIENCE AND EDUCATIONAL BACKGROUND.

A. I was employed by Arizona Water Company in September 1980 as an Engineer. I was promoted to Senior Engineer in 1985, Engineering Manager in 1989, and in 1996 to Vice President – Engineering.

I completed my college degree at Arizona State University and received a B.S.M.E. I became a Certified Professional Engineer in 1985. I am currently a member of the American Water Works Association.

II. <u>Purpose and Extent of Testimony</u>

Q. WHAT IS THE PURPOSE AND EXTENT OF YOUR TESTIMONY?

A. My testimony discusses the Company's planning and budgeting process for the construction of plant additions and improvements, and summarizes those improvements for the 1990-2001 period. I will also discuss certain post test year plant additions that the Company proposes to include in rate base, shown as adjustments on Schedule B-2.

III. Description of Company-Funded Construction Budgeting Procedures

Q. WHAT PROCEDURE DOES THE COMPANY UTILIZE TO IDENTIFY A COMPANY-FUNDED CONSTRUCTION PROJECT?

A. Each year the Company prepares a construction budget for each of its 18 water systems for the upcoming year. The budgeting process starts with the division manager who prepares a proposed construction budget for the water systems he manages. In his proposed construction budget, the manager emphasizes improving or maintaining the infrastructure needed to serve existing customers based on his experience and personal knowledge of the water system. For example, a manager may request construction of a storage tank, replacement or upsizing of a booster pump station, a new well, the replacement of a water main or the installation of a new transmission line, as may be needed, in his judgment, to ensure safe and reliable service.

Five days are set aside each year when the division managers and the Company's Engineering and Operations Departments and senior management meet to review and discuss each proposed construction project. Upon completion of this process, a final construction budget is prepared and presented to the Company's Board of Directors for review and approval.

Q. WHO DETERMINES HOW MUCH MONEY WILL BE SPENT ON COMPANY-FUNDED PROJECTS?

A. The Company's Board of Directors establishes the dollar amount of the annual construction budget. This amount usually increases annually to offset the increasing costs of construction.

Q. HOW IS THE COMPANY'S CONSTRUCTION BUDGET IMPLEMENTED?

A. Once the Board of Directors approves the Company's construction budget, the division managers solicit competitive bids from independent contractors for all pipeline projects. All pipeline projects are awarded to the contractors submitting the lowest bids. Booster pump stations, tanks, and new wells are bid by the Company's Engineering Department. These projects are also awarded to the lowest bidding contractors. All Company-funded projects are inspected by Company inspectors during the course of construction to ensure compliance with Company plans and specifications and governmental approvals.

IV. <u>Description of Company-Funded Plant Additions For The Eastern Group and Proposed Inclusions In and Adjustment To Rate Base</u>

Q. MR. WHITEHEAD, WOULD YOU PLEASE SUMMARIZE THE COMPANY-FUNDED PLANT ADDITIONS FOR THE EASTERN GROUP FROM 1990 TO TEST YEAR 2001?

A. Yes. From 1990 through 2001, the test year for this rate application, the Company annually funded construction projects for each of the Eastern Group systems (Apache Junction, Bisbee, Sierra Vista, Miami, San Manuel, Oracle, Winkelman and Superior) in order to maintain infrastructure, resolve operational problems, comply with regulatory requirements, and maintain or improve water service to its customers.

As shown in the following table, the dollar amount of the plant additions to the eight water systems in the Eastern Group has generally increased at a uniform rate, with the exception of those years when high-cost projects such as new production wells or reservoirs were necessary.

ARIZONA WATER COMPANY Eastern Group Plant Additions 1990 to 2004								
	Apache Junction	Bisbee	Sierra Vista	Miami	San Manuel	Oracle	Winkelman	Superior
1990	594,243	238,666	33,220	418,451	73,086	364,699	18,943	124,472
1991	482,394	403,612	158,111	139,989	32,327	106,745	22,582	96,422
1992	673,315	121,591	90,808	423,504	13,508	29,184	10,147	134,284
1993	915,082	196,042	22,254	168,089	107,768	167,473	22,342	95,750
1994	1,127,495	243,634	42,681	166,531	14,158	234,433	15,203	130,150
1995	952,662	235,994	63,432	264,918	47,341	152,732	1,673	237,544
1996	980,817	180,649	315,860	169,362	24,069	150,494	32,972	378,882
1997	995,497	168,408	67,734	160,587	36,624	200,540	1,240	119,110
1998	3,371,194	146,402	725,854	440,633	25,564	183,450	28,582	88,206
1999	1,807,795	187,337	154,355	215,864	48,565	228,470	17,150	37,487
2000	1,472,798	282,804	143,167	211,610	10,531	52,684	1,996	193,570
Test Year 2001	4,637,742	145,067	173,341	170,726	17,265	280,574	14,324	160,238
Post Test Year 2002*	3,320,504	513,476	122,996	425,486	74,173	289,256	13,374	311,062
Proposed 2003*	8,127,680	134,000	113,500	442,500	302,250	186,000	12,750	169,500
Proposed 2004*	3,872,500	141,500	106,000	267,000	1,927,500	225,200	15,500	1,867,313

*Blanket meters and services have been adjusted to be revenue neutral.

Over the last ten years, the number of customers in Apache Junction has more than doubled. In response to the increasing water demands brought about by the increase in customers, the Company constructed four new reservoirs; one in 1990, two in 1998, and one in 2001, and drilled three wells. The wells were completed in 1999, 2000, and 2001.

In Bisbee, a new reservoir was constructed in 2000 to replace an existing storage tank, and a new well will be drilled in 2002.

Increased water demand in Sierra Vista resulted in the need to construct a new storage tank in 1992 and drill a new production well in 1998.

In Miami, four new production wells were drilled; two were completed in 1990, one in 1991, and one in 1998. A new storage tank was also completed in 1992.

Q. PLEASE DISCUSS THE COMPANY-FUNDED CONSTRUCTION THAT THE COMPANY PROPOSES TO INCLUDE IN RATE BASE.

A. The Company has included in rate base those construction projects funded by the Company that will be completed and placed in service prior to December 31, 2002. These plant additions are non-revenue producing, that is, they consist of wells, reservoirs, transmission mains and other construction projects that improve service to customers existing at the end of the test year, as opposed to providing service to new customers. For example, in early 2002, the Company drilled and equipped a new production well in Bisbee to maintain sufficient pressure and assure an adequate and reliable water supply for the Bisbee water system. Construction of a production well is a high-cost project, and it cannot be constructed in phases over several years.

Q. WHAT IS THE AMOUNT OF THE ADJUSTMENT TO RATE BASE FOR POST TEST YEAR PLANT ADDITIONS?

A. The total adjustment to rate base is $5,763,968, as shown on Schedule B-2, page 1. The adjustments for each of the eight systems are shown on pages 2 through 9 of Schedule B-2.

Q. WHY IS THE COMPANY PROPOSING A CUT-OFF DATE FOR POST TEST YEAR PLANT ADDITIONS OF DECEMBER 31, 2002?

A. All post year plant in service at the time of hearing should be included in rate base. Nevertheless, as a practical matter, December 31 is a reasonable cut-off date based on the timing of the application and the anticipated date on which the direct testimony and/or report of the Utilities Division will be due. The December 31 cut-off date will allow the Utilities Division staff and any other party ample time to verify that all plant additions have been placed in service and to verify their construction cost. Ideally, Staff would update the findings in its Staff Report to a date immediately before the hearing.

V. Plant Additions Related to Arsenic Treatment

Q. DO ANY OF THE TEST YEAR OR POST TEST YEAR ADDITIONS RELATE TO ARSENIC TREATMENT?

A. No.

Q. WHAT ARE THE COMPANY'S PLANS FOR COMPLYING WITH THE EPA'S NEW MCL FOR ARSENIC?

A. As explained by Mr. Garfield, on February 22, 2002, the Environmental Protection Agency reduced the arsenic maximum contaminant level ("MCL") under the Safe Drinking Water Act from the current MCL of 50 parts per billion ("PPB") to 10 PPB. All potable water providers must comply with the new arsenic MCL standard by January 23, 2006.

Three water systems in the Eastern Group will be affected by the new arsenic standard. Water from the Apache Junction system is produced from six deep-water wells, which have a combined capacity of 6,930 gallons per minute ("GPM"). Water from all six wells contains arsenic in concentrations greater than 10 PPB. The Apache Junction water system also receives 1,000 GPM of water from the Central Arizona Project ("CAP"), which is treated by the City of Mesa and delivered to the Apache Junction water system. The arsenic level in the untreated CAP water is approximately 3 PPB and therefore, no treatment is needed.

To comply with the new arsenic standard and meet the compliance date of January 23, 2006, the Company will need to include in its Apache Junction construction budget approximately $6,383,000 in 2003 and $2,413,000 in 2004 solely for arsenic treatment.

At this time, the Company purchases water from BHP Copper Company ("BHP") for its San Manuel water system. The arsenic level of the BHP water is 22 PPB. BHP does not treat the water it delivers to the Company. To comply with the new arsenic standard and meet the compliance date of January 23, 2006, the Company will need to include in its San Manuel construction budget approximately $1,575,000 in 2004 solely for arsenic treatment.

The Superior water system is served from two deep wells, with a combined capacity of 800 GPM. Water from both wells exceeds 10 PPB for arsenic and will have to be treated. To comply with the new arsenic standard and meet the compliance date of January 23, 2006, the Company will need to include in its 2004 Superior construction budget approximately $1,683,000 solely for arsenic treatment.

Since the Company's capital investment plans relating to arsenic treatment are outside the test year and outside the proposed post test year plant additions sought to be included in ratebase, the Company is requesting that the Commission approve for the Eastern Group the same cost recovery method that the Commission is currently considering in the Company's Northern Group Rate Case. Mr. Ralph Kennedy will further explain this approach in his direct testimony.

VI. <u>Apache Junction, Superior Rate Consolidation.</u>

Q. WHY IS THE COMPANY PROPOSING RATE CONSOLIDATION FOR APACHE JUNCTION AND SUPERIOR?

A. Within the next few years, the Apache Junction and Superior systems will be interconnected by pipelines. When interconnected, both systems will benefit by sharing storage facilities, well production, and all other benefits associated with the creation of one large integrated system.

Q. HOW DO YOU KNOW THAT THESE SYSTEMS WILL BE INTERCONNECTED WITHIN THE NEXT FEW YEARS?

A. Gold Canyon is located at the extreme southeast edge of Apache Junction along State Highway 60. Over the last seven years, the Gold Canyon area of Apache Junction has experienced rapid growth. New development in Gold Canyon includes five new golf courses, two new schools, and new subdivisions totaling approximately 4,000 new customers. Three and one-half miles southeast of Gold Canyon is the Apache Junction Certificate of Convenience & Necessity ("CC&N") at Florence Junction. The Apache Junction CC&N at Florence Junction is not currently contiguous to the CC&N which includes the communities of Apache Junction and Gold Canyon.[1]

Two years ago the Company entered into an extension agreement to extend facilities to provide water service to a proposed development called

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[1] On December 26, 2001 the Company filed an Application at the Commission to extend its CC&N from Gold Canyon to the Apache Junction CC&N at Florence Junction. This Application was made at the request of Grosvenor Holdings L.LC. so that the Company could provide water service to their proposed 1,055-lot subdivision called Entrada Del Oro.

Ranch 160, which is located in the Apache Junction CC&N at Florence Junction. The first construction phase to provide water service to Ranch 160 included drilling two deep water wells within the development. The wells were completed last year.

In addition to the Entrada Del Oro and Ranch 160 developments, the Company has received numerous requests and inquiries concerning the provision of water service to proposed developments along State Highway 60 from Gold Canyon to Florence Junction.

Also located within the Apache Junction CC&N at Florence Junction is the Superior well field. The Superior well field consists of two wells, a storage tank, a booster pump station, and a transmission line. The transmission line follows the railroad track from the well field to Superior.

A map included with this testimony and marked Exhibit 1, shows the existing Apache Junction and Superior CC&N, pending Apache Junction CC&N extensions, and proposed developments.

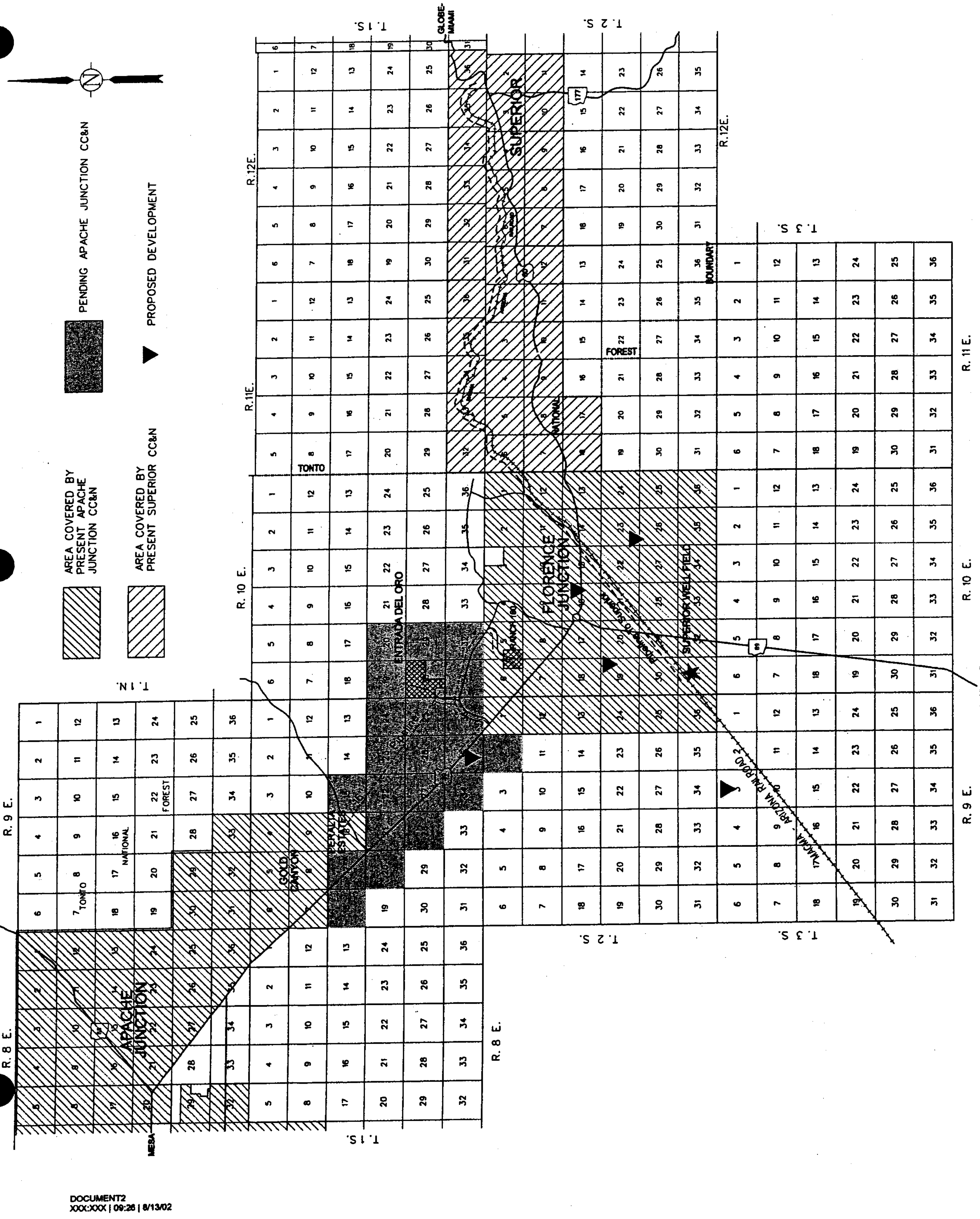
Construction of the 16-inch transmission main from Peralta Estates to the Entrada Del Oro project is scheduled to start this year. The Company included allocated funds in its 2001 Construction Budget to construct a pipeline from the Superior well field to Ranch 160 and Entrada Del Oro to provide the final interconnection between the Apache Junction and Superior systems. This Company funded project is still under design review and awaiting right-of-way clearance.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY IN THIS MATTER?

A. Yes.

EXHIBITS

EXHIBIT 1


PENDING APACHE JUNCTION CC&N
PROPOSED DEVELOPMENT
AREA COVERED BY PRESENT APACHE JUNCTION CC&N
AREA COVERED BY PRESENT SUPERIOR CC&N
APACHE JUNCTION
GOLD CANYON
PERALTA ESTATES
ENTRADA DEL ORO
FLORENCE JUNCTION
SUPERIOR
SUPERIOR WELL FIELD
TONTO
NATIONAL
FOREST
BOUNDARY
ROOSEVELT
MESA
GLOBE-MIAMI
FLORENCE
R. 8 E.
R. 9 E.
R. 10 E.
R. 11E.
R.12E.
T. 1 N.
T. 1 S.
T. 2 S.
T. 3 S.

ARIZONA WATER COMPANY

Docket No. W-1445A-02-0619

2002 RATE HEARING EXHIBIT NO. ___

For Test Year Ending 12/31/01

PREPARED

DIRECT TESTIMONY & EXHIBITS

OF

Thomas M. Zepp

EXHIBIT

A-4

Admitted

TABLE OF CONTENTS

I. Introduction and Qualifications

Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My name is Thomas M. Zepp. My business address is Suite 250, 1500 Liberty Street, S.E., Salem, Oregon 97302.

Q. WHAT IS YOUR PROFESSION AND BACKGROUND?

A. I am an economist and Vice President of Utility Resources, Inc., a consulting firm. I received my Ph.D. in Economics from the University of Florida. Prior to jointly establishing URI in 1985, I was a consultant at Zinder Companies from 1982-1985 and a senior economist on the staff of the Oregon Public Utility Commissioner between 1976-1982. Prior to 1976, I taught business and economics courses at the graduate and undergraduate levels.

I have been deposed or testified on various topics before regulatory commissions, courts and legislative committees in twenty states, before two Canadian regulatory authorities and before four Federal agencies. In addition to cost of capital studies, I have testified as to incremental costs of energy and telecommunications services and have presented rate design testimony.

Q. WHAT COST OF CAPITAL STUDIES HAVE YOU PREPARED BEFORE?

A. I have submitted studies or testified on cost of capital and other financial issues before the Interstate Commerce Commission, Bonneville Power Administration, and courts or regulatory agencies in Alaska, Arizona, California, Idaho, Illinois, Kentucky, Montana, Nevada, Oregon, Tennessee, Utah, Washington and Wyoming.

My studies and testimony have included consideration of the financial health and fair rates of return for Nevada Bell Telephone, Illinois Bell Telephone, General Telephone of the Northwest, Pacific Northwest Bell, U S WEST, Anchorage Municipal Light & Power, Pacific Power & Light, Portland General Electric, Commonwealth Edison, Northern Illinois Gas, Iowa-Illinois Gas and Electric, Puget Sound Power & Light, Idaho Power, Cascade Natural Gas, Mountain Fuel Supply, Northwest Natural Gas, California-American Water Company, California Water Service, Dominguez Water Company, Kentucky-American Water Company, Mountain Water Company, Oregon Water Company, Paradise Valley Water Company, Park Water Company, San Gabriel Valley Water Company, Southern California Water Company, Tennessee-American Water Company and Valencia Water Company. I have also prepared estimates of the appropriate rates of return for a number of hospitals in Washington, a large insurance company, and U.S. railroads.

Q. DO YOU HAVE OTHER PROFESSIONAL EXPERIENCE RELATED TO COST OF CAPITAL ISSUES?

A. Yes. I published an article "Water Utilities and Risk," <u>Water the Magazine of the National Association of Water Companies</u> Vol. 40, No. 1 Winter 1999 and was an invited speaker on the topic of risk of water utilities at the 57th Annual Western Conference of Public Utility Commissioners in June 1998. I also presented a paper "Application of the Capital Asset Pricing Model in the Regulatory Setting" at the 47th Annual Southern Economic Association Meetings and published an article "On the Use of the CAPM in Public Utility Rate Cases: Comment," <u>Financial Management</u> Autumn 1978, pp. 52-56. While on the Staff of the Oregon PUC, I also established a sample of over 500,000 observations of common stock returns and measures of risk and conducted a number of studies related to the use of various methods to estimate costs of equity for utilities. I was invited to lecture at Stanford University to discuss that research.

II. <u>Purpose of Testimony, Principles, Summary and Conclusions</u>

Q. WHAT IS THE SUBJECT OF YOUR TESTIMONY IN THIS PROCEEDING?

A. Arizona Water Company ("Arizona Water" or "Company") has asked me to estimate its cost of equity and the fair rate of return on common equity. My study is based on data available to investors in May 2002.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. In this Section II, the concept of a fair rate of return and summary of my analysis is presented. In Section III, the risk of large and small water utility common stocks and differences in risk of water utilities and gas distribution utilities are discussed. In Section IV, I discuss specific additional risks faced by Arizona Water and explain why Arizona Water's cost of equity exceeds the cost of equity of larger publicly-traded water utilities. Section V provides an overview and perspective on what one should expect the fair rate of return to be in May 2002, develops my discounted cash flow ("DCF") equity cost estimates for a sample of publicly-traded water utilities and a sample of natural gas distribution ("gas distribution") utilities, and presents an internal rate of return analysis for smaller water utilities not included in my water utility sample. Section VI presents equity cost estimates based on three risk premium approaches. Section VII provides a summary of my analysis and my recommended return on common equity ("ROE") for Arizona Water.

Q. HAVE YOU PREPARED ANY TABLES AND ATTACHMENTS TO ACCOMPANY YOUR TESTIMONY?

A. Yes. I have prepared 25 tables that support my testimony.

Q. PLEASE DISCUSS WHAT IS MEANT BY A FAIR RATE OF RETURN.

A. A fair rate of return is achieved when a utility is permitted to set rates and charges for service at levels where the expected return provides common stock investors a reasonable opportunity to earn the cost of common equity. Since operating expenses and interest on debt take precedence over payments to common stockholders, it is the common equity shareholder of the company who bears the greatest risk of receiving expected returns. In 1923, the U.S. Supreme Court set forth the following standards in the <u>Bluefield Waterworks</u> decision:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economic management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally. [262 U.S. 679, 692-93 (1923).]

In the Hope Natural Gas Company decision, issued in 1944, the U. S. Supreme Court stated the following regarding the return to owners of a company:

> [T]he return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital. [320 U.S. 591, 603 (1944).]

In 1989, in Duquesne Light Co. v Barasch, the U. S. Supreme Court recognized two important economic concepts. First, the U.S. Supreme Court held that regulatory commissions may need to adjust the risk premium element of the rate of return on equity to provide a fair return. It said:

> [W]hether a particular rate is "unjust" or "unreasonable" will depend to some extent on what is a fair rate of return given the risks under a particular ratesetting system . . . . [488 U.S. 299, 310 (1989).]

Therefore, in determining an appropriate return, consideration must be given to the specific risks created by the nature and degree of regulation to which the utility is subject, in addition to examining general economic and financial data for utilities. As I discuss further below, uncertainty with respect to costs to meet government requirements to reduce arsenic levels in water combined with reliance on historic test years reduces the chance that Arizona Water will achieve its authorized return and thus raises risk. This additional risk should be recognized when setting the fair rate of return for Arizona Water.

Second, in Duquesne, the U. S. Supreme Court stated that the cost of common stock was "the return required to sell such stock upon reasonable terms in the market." 488 U.S. at 310, n 7. The source of funds that would be used to buy such shares does not change that cost of equity. Owners of the utility could be individuals who bought stock on margin or bought it with their own funds. Owners could also be a partnership, a developer, a holding company or some other type of owner. Knowledge about ownership, however, does not change that underlying cost of equity and thus is irrelevant to a determination of the cost of equity and fair rate of return. For companies that have no publicly-traded common stock, like Arizona Water, as well as those that do, the U. S. Supreme Court found the test of a fair rate of return is tied to the issue of new shares of common stock.

Below, I explain that small firms are more risky than larger firms. In the case of Arizona Water, it is appropriate to recognize that small firms have higher equity costs and thus the return required to sell common stock for such small firms on reasonable terms would be higher than the return investors require to buy shares of larger firms.

Q. WHAT ARE THE IMPLICATIONS FOR ARIZONA WATER OF THE PRINCIPLES YOU HAVE DISCUSSED?

A. The principles are important to bondholders, ratepayers and equity owners of Arizona Water. From the perspective of bondholders, authorized rates need to be sufficient to assure current and prospective bondholders that Arizona Water will have earnings comparable to other utilities having similar risk. Otherwise, the acceptance of Arizona Water bonds will decline and bond costs increase. Such increases in bond costs will require rate increases and disadvantage ratepayers as well as bondholders. This is especially important if a company's source of external long-term financing is limited to the bond market, as is the case with Arizona Water. From the perspective of ratepayers and equity owners, the principles require rates which provide a reasonable opportunity to earn a return for its owners that is commensurate with returns on investments in other enterprises having corresponding risks and that are sufficient to attract capital on reasonable terms. As I discuss further below, Arizona Water is more risky than the water utilities sample I rely upon to determine benchmark estimates of the cost of equity and thus its required common equity return is higher. From the perspective of ratepayers, the rates they pay should provide a reasonable opportunity for Arizona Water to earn that fair rate of return. That fair rate of return on common equity is the cost of common equity.

Q. PLEASE SUMMARIZE YOUR TESTIMONY?

A. My findings and recommendations are the following:

1. The cost of common equity that faces Arizona Water is greater than the cost of common equity that faces the utilities in my publicly-traded water utilities sample:

    (a) Arizona Water is smaller and is made up of even smaller systems and therefore requires an equity cost risk premium to compensate for its small size. A study of publicly-traded water utilities shows the size risk premium is approximately 99 basis points. An Ibbotson Associates study shows companies the size of Arizona Water require no less than a 113 basis point risk premium.

    (b) Arizona Water faces new risks from the uncertainty of being able to place bonds at reasonable rates. This is a new risk related to its small size that was not present in the past.

    (c) Arizona Water is more risky because it is not publicly traded and thus has less financing flexibility than companies that are.

    (d) Arizona Water also is more risky because its new rates will be based on an historical test year which investors would expect cannot be adjusted to recognize all reasonable post test-year adjustments in capital additions and operating costs required to give Arizona Water a reasonable opportunity to earn a fair return.

    (e) Arizona Water faces significant risks resulting from current and new EPA requirements for greatly reducing the levels of arsenic in delivered water.

The need to remove arsenic exposes Arizona Water to risks related to making substantial new investments, timely recovery of costs, uncertain recovery of additional operating expenses and the burden of disposal of the arsenic that is removed. Adherence to an historical test year with limited ability to make post test-year adjustments adds to that risk.

(f) Combined, these company specific risks indicate Arizona Water's cost of equity is no less than 100 to 150 basis points above the cost of equity for a larger publicly-traded water utility.

2. The market cost of common equity facing large, publicly-traded water utilities falls in a range of 10.9% to 11.4% at this time:

- DCF model estimates for a sample of larger, publicly-traded water utilities indicate the cost of equity falls in a range of 11.0% to 11.1%;

- Comparison of estimates of risk for publicly-traded gas distribution and water utilities indicates equity cost estimates based on a sample of gas distribution utilities provide useful benchmarks to make indirect estimates of the cost of equity for publicly-traded water utilities.

- A DCF analysis of gas distribution utilities indicates the cost of equity for large, publicly-traded water utilities falls in a range of 11.1% to 11.2%; and

- Costs of equity derived from three risk premium analyses indicates the cost of equity for large, publicly-traded utilities falls in the range of 10.9% to 11.4%.

3. A risk premium of no less than 100 to 150 basis points above the equity cost of a large, publicly-traded water utility must be recognized in the authorized ROE to provide Arizona Water a fair rate of return.

4. Arizona Water's cost of equity falls in a range of 11.9% to 12.9%. I recommend that Arizona Water be allowed to earn an ROE of no less than 12.4%.

III. Risks of Water and Gas Distribution Utility Stocks

Q. AS A PRELIMINARY MATTER, PLEASE DISCUSS THE SAMPLES OF UTILITIES YOU HAVE USED IN YOUR DCF ANALYSIS.

A. Market data is required to estimate the cost of equity for a utility. Acquisitions and buyouts now in progress have substantially reduced the number of publicly-traded water utilities available to make forward-looking estimates of the cost of equity. And, for the water utilities that are still available, investor anticipations that they may be condemned by public authorities, may be acquired at a premium or may merge with another company makes it difficult to apply a standard version of the discounted cash flow model to estimate equity costs. These factors reduce the water utility sample I rely upon in my analysis to only four companies. To supplement this small sample, I conducted a DCF analysis with data for a sample of eight gas distribution utilities.

Q. HOW DID YOU DETERMINE THE SAMPLE OF WATER UTILITIES TO MAKE YOUR DCF BENCHMARK EQUITY COST ESTIMATES?

A. My sample of water utilities is composed of American States Water, California Water Service Group, Philadelphia Suburban Corp and SJW Corp. These four water utilities are all of the water utilities ACC Staff relied upon to determine DCF equity costs in the Green Valley Water Company case (Docket No. W-02025A-01-0559, Schedule JMR-5, dated February 11, 2002) that have over 65% of their revenues from water utility operations, are not currently being acquired or investors appear to believe they are acquisition targets. Table 1 lists operating revenues and net plant for these four water utilities and for Arizona Water as well as the four other water utilities in the ACC Staff sample that I have not included.

Q. PLEASE ELABORATE ON THE REASONS YOU HAVE NOT INCLUDED THE OTHER FOUR WATER UTILITIES IN THE SAMPLE YOU USED TO MAKE DCF EQUITY COST?

A. I have not included American Water Works in my sample because it has entered into an agreement under which Thames Water will acquire American's common stock at a price premium of 35% over the price at the time of the announcement. Consequently, shares of stock for American Water Works trade primarily on the expected timing of completion of the merger, not the cost of equity. Southwest Water was excluded because *C. A. Turner*

Utility Reports lists its percentage of water utility revenues at only 44%. Middlesex Water Company and Connecticut Water Services appear to be acquisition targets and thus it is difficult to estimate their equity costs with the traditional DCF model.

Table 2 reports premiums water utility investors have received, or in the case of American Water Works, have been proposed to receive, at the time mergers or acquisitions were completed. Those premiums have ranged from 35% to 59% and have averaged 45%. *Value Line* has advised investors to expect such acquisitions and mergers to continue. For example, on April 29, 2002, Philadelphia Suburban announced its proposed merger with Pennichuck Corporation, which serves approximately 120,000 people in New Hampshire. Under these circumstances, it is reasonable to expect investors have bid up prices for water utility stocks to reflect the probability they will receive similar premiums in the future. If prices have been bid up in expectation of receiving such premiums, dividend yields will be bid down to a level lower than would occur if investors did not expect such premiums to be paid and thus mechanical application of the traditional DCF model will understate costs of equity.

Potential acquisition/merger candidates are expected to have relatively high prices. To be conservative, I have left Philadelphia Suburban in my DCF sample, even though its dividend yield may be biased downward. I have, however, excluded Connecticut Water and Middlesex from my primary DCF equity cost estimates. Those two companies have experienced increases in common stock prices that are substantially above the increases in prices for other water utility stocks and thus appear to be acquisition or merger candidates.

Q. HOW DID YOU DETERMINE THE SAMPLE OF GAS DISTRIBUTION UTILITIES YOU USED TO COMPUTE YOUR OTHER DCF EQUITY COST ESTIMATES?

A. Table 3 reports the gas distribution utilities ("gas utilities") that have been relied upon to supplement my analysis and to provide another equity cost benchmark. The utilities in the gas utility sample are all of the gas utilities that ACC Staff relied upon in Black Mountain Gas Company's recent rate case, Docket No. G-03703A-01-0263, to make DCF equity cost estimates that have at least one bond rating from Moody's or S&P that is single-A or higher and have at least 65% of revenues derived from gas operations.

Q. **HOW DOES THE LEVEL OF RISK FACED BY GAS AND WATER UTILITIES COMPARE?**

A. When making comparisons between risks of water utilities and gas distribution utilities, investors recognize that all utilities face the risk that regulators may disallow investments they have made and expenses they incur. That is an unavoidable risk of regulation. In general, however, the other types of risks facing gas utilities and water utilities are different. It is possible, however, to compare two "bottom-line" measures of risk for an average gas utility with comparable measures of risk for the average water utility. That comparison is presented in Table 4. The first measure of risk is beta, the risk measure in the capital asset pricing model. The beta provides a measure of the risk of holding a stock in a diversified portfolio. The larger the beta, the higher the risk. For purposes of this table, *Value Line* estimates of betas are presented. The second measure of risk is *Value Line*'s Safety Rank. This measure of risk is the risk an investor has if he/she holds an individual stock instead of holding that stock as part of a diversified portfolio. The larger the Safety Rank, the higher the risk. Based on those measures of risk, gas and water utilities have approximately the same level of risk.

Q. **IS THERE OTHER EVIDENCE THAT SUGGESTS THE FINANCIAL COMMUNITY REGARDS THE RISK OF WATER UTILITIES AND GAS UTILITIES TO BE SIMILAR?**

A. Yes. In its June 21, 1999 *Utilities & Perspectives*, Standard & Poor's announced that it "has created a single set of financial targets that can be applied across the different utility segments." It now has "four principal financial targets that it uses to analyze credit quality of ***all*** investor-owned electric, natural gas, and water utilities in the U.S." S&P *Utilities & Perspectives*, June 21, 1999, Vol. 6, No. 25, page 2 (emphasis added). Past separate targets for water utilities are gone. This decision by S&P together with the evidence on risk measures in Table 4 provides support for using equity costs derived from data for samples of gas utilities to make other benchmark estimates of the cost of equity.

Q. DOES A WATER UTILITY FACE MORE RISK WHEN IT HAS TO MAKE ADDITIONAL INVESTMENTS TO MEET STATE AND FEDERAL WATER QUALITY STANDARDS?

A. Yes. First, expected or unexpected requirements for additional capital spending means the utilities have to request rate increases more often and for larger percentage increases in order to maintain fair rates of return. Regulatory procedures are expensive, time consuming, increase uncertainty, and raise doubts in investor minds that regulators will authorize high enough rates and/or rate adjustment mechanisms to enable the utilities to earn fair rates of return. This increases uncertainty about future returns and thus increases risk. Below I point out that new investments that Arizona Water must make to remove arsenic from its water supplies (that are larger than investments required by water utilities operating primarily in other states) increases Arizona Water's risk compared to the risk of the water utilities sample in Table 1.

Second, investors are concerned that regulators will delay inclusion of new plant in rate base or not allow part of the dollars invested or operating costs incurred to be recovered. From an investor's point of view, it is the <u>potential</u> for such disallowances, delays or exclusion from consideration in setting new rates that increases risk. If additional investments were never required, the investor concerns would never arise and there would be no potential disallowances, delays or possible exclusions and thus risk would not increase. With the need for increased investments, however, the uncertainty arises and the risk increases. If a water utility is required to make investments to meet state and federal safe drinking water requirements before those investments are authorized to be included in rate base, as is currently the case in Arizona, the utility faces at least two new uncertainties: uncertainty about when and if it will be allowed a full return on the investments and uncertainty about whether it will be allowed to recover the capital and operating costs of those investments in rates.

This source of risk is of special concern to Arizona Water in this case. Rates will be based on an historical 2001 test year with limited opportunities to make post test-year adjustments for new rates which will not go into effect until July or August, 2003. With the need to make substantial new investments in arsenic treatment facilities that may not be included in rates as well as uncertainty related to recovering the expenses of operating arsenic treatment facilities, the potential for rates to be less than are needed to recover costs increases risk substantially.

Q. HAVE YOU STUDIED THE IMPACT OF FINANCING REQUIREMENTS ON THE RISK AND COSTS OF CAPITAL FACED BY UTILITIES?

A. Yes, I have. In the past, I conducted a study of expected differences in bond costs and common equity costs that faced electric utilities with different financing requirements. I found that utilities with above average financing requirements required an ROE that was approximately 80 basis points higher than was required by an average utility. Higher financing requirements pushed up bond costs, too.

IV. Specific Additional Risks Faced by Arizona Water

Q. IS ARIZONA WATER MORE RISKY THAN LARGER, PUBLICLY-TRADED UTILITIES?

A. Yes. It is more risky for a number of reasons. It has new risks related to EPA requirements to remove arsenic from water supplies that are of much less concern to other water utilities. Arizona Water also faces more risk than the utilities in the water utilities sample listed in Table 1 because it has all rates based on an historical test year with a limited ability to make post test-year adjustments. For example, in Decision No. 64282, the December 28, 2001 general rate case order for the Company's Northern Group systems, the ACC excluded from rate base $1.8 million of non-revenue producing plant that was completed and in-service 9 months before the decision. The Company is also more risky because it is smaller than the utilities in the water utilities sample. Additionally, the Company is not publicly-traded and recently has discovered it has less access to bond markets than it has had in the past. These risks and concerns mean Arizona Water requires an equity-cost risk premium above equity costs determined for the water utilities sample to provide Arizona Water a reasonable opportunity to earn a fair rate of return.

Q. AT THE BEGINNING OF YOUR TESTIMONY YOU MENTIONED THE U. S. SUPREME COURT'S DUQUESNE DECISION. DOES ARIZONA WATER FACE ANY SPECIFIC RISKS UNDER THE "PARTICULAR RATESETTING SYSTEM" IN ARIZONA THAT REQUIRE THAT THE AUTHORIZED ROE BE SET ABOVE THE MARKET COST OF EQUITY YOU DERIVE BELOW FROM DATA FOR WATER COMPANIES WHICH OPERATE IN OTHER STATES?

A. Yes, it does. In its Duquesne decision, the U. S. Supreme Court stated:

> [T]he impact of certain rates can only be evaluated in the context of the system under which they are imposed . . . . The risks a utility faces are in large part defined by the rate methodology because utilities are virtually always public monopolies dealing in an essential service, and so relatively immune to the usual market risks. [488 U.S. at 314-315.]

I am aware of a state-specific factor in Arizona which makes Arizona Water more risky than the utilities in the water utilities sample I rely upon to make benchmark cost of equity estimates. Arizona Water has filed for rate increases based on a calendar year 2001 test year. The Company's application is being prepared in 2002. The case will not be heard until early 2003. New rates will not be put into place until the third quarter of 2003.

Finally, the Arizona Constitution, as interpreted in recent court decisions, limits the ability of Arizona utilities to utilize adjustment mechanisms, advice letter findings and other streamlined procedures to obtain recovery of costs outside a general rate case, in contrast to many other jurisdictions. These limitations on obtaining rate relief constitute a "particular ratesetting system" in Arizona that makes it more risky for a utility, like Arizona Water, which has all of its operations in Arizona, to do business in Arizona than in the states that have future test years or modify historic test years to fully reflect future costs with post test-year adjustments[1]. Under the Duquesne decision, the additional risk associated with the "particular ratesetting system" must be compensated with an ROE that is higher than would be appropriate for the utilities in the water utilities sample.

Q. ARE ARSENIC LEVELS A SPECIAL CONCERN TO ARIZONA WATER?

A. Yes. A particular concern in Arizona is EPA's revision of the arsenic drinking water standard, under which the maximum contaminant level ("MCL") is reduced from 50 ppb to 10 ppb. Arsenic is naturally occurring and is relatively common in the southwestern region of the United States. From a risk standpoint, this new regulation will have a much greater impact on water utilities in Arizona and other areas of the southwest than in other parts of the country where the occurrence of arsenic in water supplies is minimal. The impact on Arizona Water increases its risk in at least four ways. (1) The Company faces all of the risk that flows from having to make substantial new investments in non-revenue producing arsenic treatment facilities to meet the EPA requirements; (2) Risk increases because Arizona Water will not receive timely rate relief to recover those investment costs and related operating costs when it must rely upon an historical test period with limited post-test-year adjustments. (3) Although there has been progress in the Phase II Arsenic Cost Recovery proceedings, only limited step increases for the capital costs of the

[1] Unless the 2001 test year is modified to allow reasonable post test year adjustments that reflect the future relationship between potential sales, rate base and expenses, new rates will not be high enough to allow Arizona Water the opportunity to earn a fair rate of return.

Northern Group's completed arsenic treatment facilities are envisioned and a final Decision has not been reached. Moreover, there is no mechanism to recover the increased expenses of operating the arsenic treatment facilities -- costs that are estimated to equal the capital costs -- other than a full rate case. (4) Finally, the Company faces substantial risks related to unknown challenges arising from the need to dispose of the arsenic that is removed.

Q. PLEASE EXPLAIN WHY THE NEED TO MAKE SUBSTANTIAL NEW INVESTMENTS TO REMOVE ARSENIC INCREASES RISK?

A. EPA's new arsenic MCL of 10 ppb will require Arizona Water to make substantial new investments in non-revenue producing facilities which would otherwise not be required and are not required by water utilities that do not face similar arsenic levels. The additional facilities are non-revenue producing because they will not expand the Company's ability to serve new customers but will merely increase the Company's investment per customer. In assessing the impacts of meeting the EPA's 10 ppb arsenic MCL, Arizona Water has completed two cost estimates. The first estimate prepared for a report to the EPA in September 2000 estimated that the total Company-wide capital cost of meeting a 5 ppb MCL level would be $50.7 million. Now that the MCL has been set at 10 ppb, the Company has prepared a new study that estimates total capital costs of $30 million. The Eastern Group capital costs represent $12 million of this total. In Section III above, I explained why the need to make new investments increases risk and discussed a study I made which found utilities that must make above-average investments have equity costs that are 80 basis points higher than utilities with average investment requirements. My discussion and the results of that study indicate Arizona Water also requires a risk premium that is not required by utilities that do not have the same investment requirements.

Q. HOW DOES THIS INCREASE IN INVESTMENT IMPACT THE NEED TO SEEK RATE RELIEF?

A. It means Arizona Water will need to seek higher rates and more frequent rate relief than utilities that do not have the same investment requirements. Even if the proposed step increase procedure is approved for the Northern Group capital costs, once the required arsenic treatment capacity is installed, there will be a further large increase in the Company's revenue requirement due to the impact of the treatment plants on operating and maintenance expenses and property taxes. There will also be increases in depreciation expenses, debt service and ROE requirements for the capital costs not covered by whatever step increase procedures may be approved. Generally, rate relief must be requested <u>prior</u> to investments being made, if the utility is to recover all of its costs. If such investments and operating costs are not recognized for Arizona Water because of the ACC's strict adherence to an historical test period, the uncertainty of the Company actually earning its authorized ROE will increase substantially. Without a mechanism for the Company to recover the substantial operating and maintenance expenses of the new arsenic treatment facilities, there is little chance that the Company will be able to earn its authorized ROE over the period 2003 through 2007. Unfortunately this is also the period when the Company will be facing unprecedented financing needs.

Q. WHAT ARE THE CONCERNS WITH OPERATING COSTS?

A. When the new arsenic treatment facilities are placed in service, operating costs will increase by a significant but uncertain amount. There will be uncertainty (and thus more risk) that occurs with such increased water treatment costs, even if the ACC allows reasonable post test-year adjustments designed to recover such expected costs. If reasonable post-test-year adjustments in test-year expenses are not allowed, it will assure the Company makes less than a fair rate of return.

Q. WHAT ARE THE RISKS RELATED TO DISPOSAL OF ARSENIC?

A. Arizona Water will have to dispose of the arsenic removed from the water. Disposal procedures and requirements will impose significant new burdens that carry their own costs and safety concerns that add further to the risk the Company faces from the requirement to remove more arsenic from its water supplies.

Q. PLEASE SUMMARIZE WHY RISK INCREASES WITH MORE STRINGENT ARSENIC TREATMENT REQUIREMENTS?

A. With respect to investments to meet the new arsenic MCL and related operating and disposal costs, Arizona Water's risk will increase when compared to business risks of the utilities in the water utilities sample that do not operate primarily in Arizona and do not have large arsenic treatment exposures. That risk will be compounded if the ACC will not allow for reasonable post-test-year adjustments or other mechanisms that allow the Company to charge rates or adjust future rates to reflect those added costs. With the need to meet new arsenic treatment requirements, a strict adherence to an historical test year would increase risk and place severe burdens on Arizona Water.

Q. ARE SMALL WATER UTILITIES MORE OR LESS RISKY THAN LARGER, PUBLICLY-TRADED UTILITIES?

A. Small water utilities are more risky than larger ones and require higher equity returns to compensate for higher risk even when they have above-average common equity ratios. Table 1 shows Arizona Water has operating revenues and net plant that are less than 25% as large as the respective averages of the water utilities sample I use to make equity costs.

Q. IS THERE EVIDENCE THAT SHOWS SIZE HAS AN IMPACT ON THE COST OF EQUITY?

A. Yes, evidence for companies in general, and water utilities in particular, indicates smaller companies have higher costs of equity.

Formal academic studies have addressed the issue of company size and risk and have found that, in general, smaller firms are more risky. One of the risk measures presented in Table 4 is called beta risk. Eugene Fama and Kenneth French conducted empirical studies that show when beta risk is the same for companies, smaller companies are generally more risky than larger ones. "Industry Costs of Equity," 43 *Journal of Financial Economics* (1997) pp. 153-193.

Ibbotson Associates have studied the issue for several years and found that beta risk is higher for small firms and that even accounting for higher beta risk, those small firms require higher returns than would be predicted by the simple capital asset pricing model. Three of the tables from the 2002 Ibbotson Associates studies are reproduced here as Tables 5, 6, and 7.[2] Tables 6 and 7 show that, in general, smaller companies have more beta risk than larger companies and that even if two companies have the same beta risk, but one company is smaller than the other, the smaller company requires a higher return than the larger one.

Tables 6 and 7 display Ibbotson Associates' estimates of average betas (estimated in two different ways) and size premiums for typical companies of different size. Assuming Arizona Water common shares would trade at a market-to-book ratio similar to publicly-traded water utilities, the market value of Arizona Water would fall into the Micro-cap category. The utilities in the water utilities sample have an average capitalization size that would put them in the Low-Cap size category. With such market valuations, the Ibbotson Associates studies indicate the size risk premium for Arizona Water is 113 to 188 basis points higher than the size premium for the average water utility in the water utilities sample.

Q. HAVE ANY REGULATORY COMMISSIONS STUDIED THE DIFFERENCES IN

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[2] Ibbotson Associates, *Stocks, Bonds, Bills and Inflation, 2002 Yearbook Valuation Edition*. Tables 7-2, reproduced here as Table 5, shows the largest companies in each of the ten deciles. Tables 7-5 and 7-8, reproduced here as Tables 6 and 7, show the range of estimated results from the Ibbotson Associates studies.

RISK OF SMALL AND LARGE WATER UTILITIES?

A. Yes, Staff of the California Public Utilities Commission ("CPUC") made such a study for water utilities. The CPUC Staff estimated proxies for beta risk with accounting data for 58 small water utilities and found that smaller water utilities (Class C and Class D) required equity returns higher than the larger Class A water utilities, even though those small water utilities were financed with 100% common equity. Business risk increases as the size of a firm decreases. This increase in business risk more than offsets the lower financial risk that would accompany 100% common equity. *Staff Report on Issues Related to Small Water Utilities*, June 10, 1991 and CPUC Decision 92-03-093. In a subsequent proceeding, the CPUC also found that a smaller Class A water utility required a higher ROE than the larger Class A water utilities.[3]

Q. **HAVE YOU CONDUCTED ANY NEW STUDIES THAT SHOW SMALL WATER UTILITIES HAVE HIGHER COSTS OF EQUITY THAN LARGER ONES?**

A. Yes. Market information is required to estimate equity costs. It is generally difficult to find useful market information for small water utilities because many of the small firms, such as Arizona Water, are not publicly traded. Market data required to make DCF equity cost estimates for four water utilities in California, however, were available to conduct such an analysis for the period 1987 to 1997[4]. My study compared average equity costs of

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[3] The CPUC determined that a small Class A water utility (Park Water Company) has greater overall risk than larger publicly-traded water utilities. In Decision 99-03-032, Application 98-03-024, the Commission issued the Finding of Fact below:

> 27. While Park's slightly higher equity ratio than the average of RRB's "comparable" group serves to somewhat lessen its financial risk, this is more than offset by Park's small size, limited financial flexibility, demonstrated higher costs to borrow, and greater vulnerability to the risks of catastrophic events which produce significantly higher business risks, leading to our finding that Park presents an overall higher risk as perceived by investors, so that the ROE expected in an adjusted quantitative analysis for the RRB "comparable" group should serve as a floor above which Park should be compensated.

In Finding of Fact 28 the CPUC also found ". . . "Park's greater overall risk to investors represents an additional 30 basis points."

[4] Basing the study on companies in the same state reduces concerns about the study results being

the two smaller water utilities, Dominguez Water Company and SJW Corporation (San Jose Water), with equity costs for the two larger companies, California Water Service and American States Water. The results of my analysis are provided in Table 8. It shows that the smaller water utilities had a cost of equity that, on average, was 99 basis points higher than the average cost of equity for the larger water utilities. The t-statistic reported in Table 8 shows that, at a 90% level of confidence, the cost of equity for the smaller water utilities is statistically significantly higher than the cost of equity for the larger water utilities. It is not possible to conclude, however, that the required return for the smaller water utilities is less than the 113 basis point size effect found by Ibbotson Associates that I report in Table 7.

This market information provides an estimate of part of the risk premium required by Arizona Water. Table 1 shows Arizona Water is less than 25% as large as the water utilities I use to determine benchmark DCF equity cost estimates and thus Arizona Water has a higher cost of equity. Based on the measures of size in Table 1, Arizona Water falls between the size of SJW Corp and Dominguez Water Company. Thus, an appropriate risk premium for Arizona Water will include the 99 basis point risk premium as well as risk premiums required to compensate the Company for other company-specific risks.

Q. ARE THERE OTHER RISKS RELATED TO SIZE THAT WOULD NOT BE REFLECTED IN YOUR STUDY?

A. Yes. Mr. Kennedy has informed me that in attempting to market its Series K bonds in late 2000 the Company solicited proposals from its traditional bond investors to determine their interest in Arizona Water's new bond issue. Insurance companies are the typical source of debt financing for small utilities the size of Arizona Water that do not issue large debt issues. He found that those traditional lenders were no longer interested in purchasing bonds in amounts less than $20 million, and in general, were now focusing on

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dependent upon differences in regulatory risks or geographic risks.

buying issues of $50 million or more. If this source of debt financing dries up or is substantially limited, it will increase a small water utility's risk of financing new projects on reasonable terms.

Q. PLEASE EXPAND ON THAT LAST POINT. IS THIS CHANGE IN MARKET ACCEPTANCE OF BONDS A MAJOR CONCERN FOR PRIVATELY-HELD UTILITIES SUCH AS ARIZONA WATER?

A. Yes. Arizona Water is not publicly traded and thus has less financing flexibility than publicly-traded utilities. When new capital is required, a publicly-traded utility can issue either bonds or common shares to maintain its capital structure. A closely held utility cannot. It must rely upon future retained earnings to keep its capital structure in balance. The change in market acceptance of bonds from small utilities I discussed above, then, is a special problem for Arizona Water because bond financing is the Company's only source of external long-term financing.

Q. DO THESE RISKS INCREASE ARIZONA WATER'S COST OF EQUITY?

A. Yes. Evidence I presented above shows that because Arizona Water is smaller than utilities in the water utilities sample, it requires no less than a 99 basis point risk premium. Also, the Company is going to have to undertake significant new investments to address new EPA requirements to remove arsenic. A past study I conducted found that utilities that must make above-average investments require a risk premium of 80 basis points. Arizona Water also requires a risk premium to offset the risk of having to make significant investments to meet the new EPA requirements. I also explained why the ACC's strict adherence to an historical test period and Arizona Water's lack of financing flexibility increase risk. Taking into account Arizona Water's exposure to the various risks, including the 99 basis points I estimate is required just to compensate for its small size, I conclude Arizona Water requires an equity cost risk premium above the benchmark cost of equity estimates for larger water and gas distribution utilities of no less than 100 to 150 basis points at this time.

V. <u>DCF Estimates of the Benchmark Cost of Equity</u>

Q. DO YOU HAVE ANY GENERAL OBSERVATIONS ABOUT FINANCIAL CONDITIONS AND FORECASTS THAT PROVIDE PERSPECTIVE ABOUT THE COST OF EQUITY NOW FACED BY ARIZONA WATER?

A. Yes. Table 9 shows that, with the exception of the year 2000, interest rates for Baa Corporate bonds are higher today than they were in every year since 1996. To the extent that changes in interest rates reflect changes in costs of equity for Arizona Water, Baa bond rates provide a better perspective than changes in rates for short-term bonds or Treasury securities. During 2001, short-term rates dropped precipitously as the Federal Reserve Open Market Committee took actions to stimulate the economy. Arizona Water's equity cost, however, is a long-term cost of capital. But long-term Treasury rates not only reflect the underlying cost of capital but also lower rates resulting from a flight to quality during the recent recession and from investors bidding up the price of such securities in anticipation of fewer Treasury bonds being available with a smaller national debt. Thus, utility costs of equity are more closely tied to the cost of long-term Baa bonds. Though rates on Baa bonds dropped in 2001 from the levels prevailing in 2000, they are now back up and a consensus forecast made by numerous financial institutions and compiled by Blue Chip indicates interest rates are expected to remain above levels that prevailed in five of the last six years.

Q. WHAT IS SHOWN IN TABLE 10?

A. Table 10 provides a list of ROEs authorized for gas, sewer and water utilities by the ACC since 1996 in cases where ROE was a litigated issue. In all but the most recent Arizona Water case, the authorized ROEs were in a range of 10.5% to 12.0%.

Q. WHAT IS THE SIGNIFICANCE OF THOSE DECISIONS?

A. Currently the Baa interest rate and forecasted Baa rates are near the top of the 7.22% to

8.37% range for Baa bond rates shown in Table 9. To the extent that costs of equity are related to the prevailing level of interest rates and forecasted interest rates, those decisions provide a useful perspective to determine what is a fair rate of return today. Arizona Water's cost of equity is above that benchmark range because it has additional risks discussed in Section IV above.

Q. HOW DO YOU EXPLAIN RECENT ACC STAFF RECOMMENDATIONS IN GREEN VALLEY AND OTHER CASES TO SET AUTHORIZED ROEs AT MUCH LOWER LEVELS?

A. Such recommendations must be the result of (a) changes in the methods now being used by ACC Staff to estimate equity costs and (b) subjective judgments being made by ACC Staff when they implement the various equity cost estimation models. They are ***not*** the result of changes in the basic cost of credit reflected by interest rates. Rates for Baa utility bonds and forecasted rates for Baa bonds are near the top of the range of Baa rates that prevailed in the period since 1996 when the ACC found equity returns substantially higher than are currently being recommended by ACC Staff were reasonable.

Q. ARE THE EQUITY COST ESTIMATES YOU PRESENT BELOW CONSISTENT WITH THE DATA IN TABLES 9 AND 10?

A. Yes. The equity cost estimates I present below are consistent with interest rates being near the top of the range of interest rates prevailing since 1996 and Arizona Water's additional risks.

Q. PLEASE PROVIDE AN OVERVIEW OF YOUR APPROACH TO THE DETERMINATION OF DCF EQUITY COST ESTIMATES.

A. An ROE for Arizona Water that is fair to ratepayers, allows Arizona Water to attract capital on reasonable terms, and maintain its financial integrity is the company's cost of equity. That return should be commensurate with returns investors expect to earn on investments of comparable risk. To estimate that cost of equity, the analyst requires market data that reveal investors' required returns, but such data are not available for Arizona Water. There is no "pure play" company that is perfectly comparable to Arizona Water. The utilities in the water utilities sample, however, provide the same service and thus provide a useful starting point in the determination of Arizona Water's cost of equity. As shown in Table 4, the gas utilities in the sample used to make additional equity cost estimates have beta risk and safety ranks comparable to the utilities in the water utilities sample and thus equity costs based on that gas utilities sample also provides another useful equity cost benchmark.

As explained above, Arizona Water is more risky than the utilities in the water utilities and gas utilities samples because it is smaller and has other additional risks related to arsenic treatment and historical tests years and thus has higher business risks than the utilities in Table 1. In this section of my testimony, I determine average equity costs for the two utilities samples based on the DCF model. Arizona Water's equity cost is higher than those benchmark estimates because it is more risky and thus I add 100 to 150 basis points to those equity cost estimates to determine the cost of equity for Arizona Water.

Q. **PLEASE EXPLAIN THE DCF METHOD OF ESTIMATING THE COST OF EQUITY.**

A. The DCF model computes the cost of equity as the sum of an expected dividend yield (D_1/P_0) and expected dividend growth (g). The expected dividend yield is computed as the ratio of next period's expected dividend (D_1) divided by the current stock price (P_0). Generally, the constant growth DCF model is computed with formula (1) or (2):

(1) $\text{Equity Cost} = D_0/P_0 \times (1 + g) + g$

(2) $\text{Equity Cost} = D_1/P_0 + g$

where D_0/P_0 is the current dividend yield and D_1/P_0 is found by increasing the current yield by the growth rate. The DCF model is derived from the valuation model shown in equation 3 below:

(3) $P_0 = D_1/(1+k) + D_2/(1+k)^2 + \ldots + D\infty/(1+k)\infty$,

or, alternatively,

(4) $P_0 = D_1/(1+k) + D_2/(1+k)^2 + E(P_2)/(1+k)^2$,

where

(5) $E(P_2) = D_3/(1+k) + D_4/(1+k)^2 + \ldots + D\infty/(1+k)\infty$,

and where k is the cost of equity; P_0 is the current stock price, $D_1, D_2, \ldots D\infty$ are the cash flows expected to be received in periods 1, 2, . . . ∞, respectively; and $E(P_2)$ is the price the investor expects to receive at the end of the second period. If investors expected the utility to be a merger/acquisition candidate, $E(P_2)$ would be the expected cash or the value of securities offered in the merger or acquisition.

Q. **DO YOU HAVE ANY SPECIAL CONCERNS WITH USING THE DCF MODEL TO ESTIMATE EQUITY COSTS FOR WATER UTILITIES AT THIS TIME?**

A. Yes. If investors expect a water utility stock is a potential merger/acquisition candidate they will bid up the price (and thus bid down the yield) to reflect the probability and price expected from the merger/acquisition. Table 2 reports premiums investors have recently received or expect to receive from mergers and acquisitions have been in a range of 35% to 59%. With reference to equation (4) above, if investors expect similar premiums for another water utility, the current price (P_0) will be bid up to reflect the expected price from the acquisition instead of the stream of future cash flows shown in equation (5). In such a situation, investors do not expect a constant growth in cash flows and thus the constant growth DCF model no longer applies.

Q. **WHAT IS THE IMPLICATION OF INVESTORS HAVING GOOD REASON TO EXPECT ADDITIONAL MERGERS AND ACQUISITIONS IN THE WATER UTILITY INDUSTRY?**

A. The implication is that a mechanical application of the DCF model will understate the cost of equity. If investors have good reason to believe other water utilities are targets for acquisitions or mergers, they will give weight to two alternative scenarios. Referring to equation (4), in scenario A, investors will consider how much to pay today (P_0) in anticipation of receiving a premium future price $E(P_2)$ for their water utility stock after a merger or acquisition. In scenario B, the investor will determine how much to pay today for the stock based on the future cash flow expected if no merger occurs. In situations where the constant growth DCF model is useful, little if any weight would be given to scenario A and the focus would be on scenario B. However, given recent merger and acquisition activity in the water utility industry, rational investors would give weight to scenario A. To the extent that they do, water utility stock prices are bid up, dividend yields are bid down and mechanical application of the constant growth DCF model will understate the cost of equity.

Q. GIVEN YOUR CONCERNS WITH MARKET PRICES FOR WATER UTILITY STOCKS REFLECTING POTENTIAL FUTURE PREMIUMS FROM MERGERS, HOW HAVE YOU PROCEEDED IN THIS CASE?

A. Initially, I use data for the four utilities in the water utilities sample and data for the eight utilities in the gas utilities sample to make DCF equity cost estimates with equation (2). Because all water utilities may have prices somewhat biased upward as investors bid up prices in anticipation of the next, currently unknown, acquisition offer, the DCF equity cost estimate for the comparable risk gas utilities sample becomes very important in my considerations.

Q. HOW DID YOU COMPUTE CURRENT DIVIDEND YIELDS?

A. The current dividend yield (D_o /P_o) is computed as the average of the highest and lowest dividend yields during two periods ending in April 2002. The value for D_o is computed as the sum of the current indicated quarterly dividend and the three prior quarterly dividends for each stock. The high and low prices used to compute the dividend yields are found from data for the 3-month and 12-month periods ending in April 2002. Estimates of dividend yields (i.e, in equation 1, D_0/P_0) are reported in Table 11. As of the end of April 2002, the 3-month average dividend yield is 3.4% and the 12-month average dividend yield is 3.5% for the water utilities sample.

Q. HOW DID YOU ESTIMATE GROWTH RATES?

A. In estimating growth rates, I assume investors rely upon analysts' forecasts of future sustainable growth and forecasts of future EPS growth when they form their opinions about future expected growth prospects. To the extent that past DPS and EPS growth provide an indication of future growth prospects, I assume the analysts have taken such past information into account when they formed their forecasts of the future[5].

Once such growth estimates are made, investors buy or sell shares of the stocks until the expected return from the dividend yields plus the growth projections equal the investors' discount rate.

Q. WHAT DO YOU MEAN BY THE "INVESTORS' DISCOUNT RATE"?

A. The investors' discount rate for a particular stock is the discount rate for marginal[6] investors that will make the present value of all expected future cash distributions to those investors equal to the market price for a share of stock. That discount rate is also the cost of equity. It is the discount rate where the supply of shares of the stock equal the demand for shares of the stock.

Q. WHAT IS SUSTAINABLE GROWTH?

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[5] This assumption is consistent with an empirical study conducted by David A. Gordon, Myron J. Gordon and Lawrence I. Gould, "Choice Among Methods of Share Yield," *Journal of Portfolio Management (Spring 1989), pp. 50-55.* They found that a consensus of analysts' forecasts of earnings per share for the next five years provides a more accurate estimate of growth required in the DCF model than 3 different historical measures of growth. They explain that this result makes sense because analysts would take into account such past growth as indicators of future growth as well as any new information. As a result, one should expect analysts' forecasts of growth to be superior measures of growth required by the DCF model.

[6] Marginal investors are those investors who last bought or sold shares of the stock. Other investors, not on the margin, may have higher discount rates and (thus do not buy the stock) or lower discount rates and thus retain their positions in the stock.

A. Sustainable growth is a useful indicator of DCF growth that can continue for a relatively long future period of time. Generally, it is derived by combining expected growth from future retained earnings and expected future growth from sales of common stock above book value.

Q. HAS THIS MEASURE OF DCF GROWTH BEEN DISCUSSED IN FINANCE LITERATURE?

A. Yes, it has. Myron Gordon is sometimes called the father of the DCF model. In his 1974 book[7], Gordon explains that sustainable growth can be expected to come from two sources: from retained earnings (called "BR" growth) and from sales of common stock when prices exceed book value (called "VS" growth) in the following formula:

$$g = BR + VS,$$

where

g = sustainable growth,

B = the retention ratio[8],

R = the expected rate of return on common equity,

V = 1 - (book value/market value), and

S = the fraction of new common equity investors expect a water utility to raise from selling more common stock.

Gordon explains why VS growth can be expected when market prices exceed book value but why VS growth is not expected to come into play when market prices are below book values.

Q. HOW DO YOU ESTIMATE EXPECTED BR GROWTH?

A. It is investors' expectations of what the retention ratio ("B") and the expected earned

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[7] M. J. Gordon, The Cost of Capital to a Public Utility, Michigan State University, East Lansing, Michigan, 1974.

[8] The retention ratio is computed as (1 - the ratio of dividends divided by earnings).

return on common equity ("R") will be in the <u>future</u> which determine this portion of expected sustainable growth. Multiplying B times R gives the estimate of future sustainable growth from retained earnings. Investors look for measures of future growth when pricing stocks. Where available, I have used *Value Line* projections of future returns on equity, future dividends per share and future earnings per share to make the forecasts of BR growth[9]. This information is probably the most widely available source of forecasted earnings and retention ratios available to investors and is adopted here for my analyses. The estimates of individual BR growth for each of the water utilities are reported in Table 12 as well as the sample average.

Q. HAVE YOU ESTIMATED VS GROWTH FOR THE WATER UTILITIES SAMPLE?

A. Yes. My estimates of VS growth for the water utilities sample are presented in Table 13. The utilities in the water utilities sample have sold stock at prices in excess of book value in recent years and have thus achieved VS growth. Knowledgeable investors would expect such VS growth in the future. Past history and available forecasts indicate investors expect publicly-traded water utilities to issue more shares of stock over time. Thus there will be a positive "S" term in VS growth. Also, the average current market-to-book ratio for the water utilities sample is over 2.0. Unless stock prices drop to less than half of their current values, there will be a positive "V" for the foreseeable future.

Q. IN THE GREEN VALLEY WATER CASE, ACC STAFF ARGUED THAT THE FINANCIAL IMPLICATION OF A MARKET-TO-BOOK RATIO GREATER THAN 1.0 IS THAT INVESTORS EXPECT WATER UTILITIES TO EARN BOOK RETURNS ON EQUITY GREATER THAN THE COSTS OF EQUITY. DO YOU AGREE?

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[9] Those data are not available for SJW Corp. Historical data for SJW Corp are all that are available and have been used in order to be able to include SJW Corp in the sample.

A. No. There are a number of reasons investors may bid up market prices for stocks above book values other than an expectation that a water utility will earn more than its cost of equity. In testimony presented before the Oregon Public Utilities Commission, Mr. John Thornton, who is now the Chief of the Accounting and Rates Section of the ACC, listed the following six reasons: (1) public utility commissions do not issues orders simultaneously in all jurisdictions, (2) not all of a company's earnings are regulated, (3) regulatory expenses, revenue and rate base adjustments may cause accounting returns to differ from those calculated on a rate case basis, (4) actual sales do not equal sales assumed in a rate case, (5) market expected ROEs change frequently while rate-case authorized ROEs do not, and (6) regulated subsidiaries constitute only a piece of a holding company pie[10]. While I agree that those six factors may explain a market price being above book value even if investors expect the water utility to earn no more than its cost of equity, there are other equally obvious reasons.

Q. WHAT ARE THESE OTHER REASONS?

A. A seventh is based on the concept of opportunity cost. Table 14 shows earned ROEs, authorized ROEs and market-to-book ratios for companies *C. A. Turner* included in its water utility category and market-to-book ratios for 721 industrial companies in what *Value Line* calls its Industrial Composite. This table shows that the level of market-to-book ratios for industrial companies provides another explanation why market-to-book ratios for water utilities exceed 1.0 even though publicly-traded water utilities have, on average, earned less than their costs of equity. Quite simply, as the composite market-to-book ratio for industrial companies has increased, so has the market-to-book ratio for publicly-traded water utilities, but by less. It appears investors take into account alternative returns that can be made from investing in industrial stocks, i.e., opportunity costs, as well as ROEs earned by publicly-traded water utilities.

[10] Testimony filed by John Thornton in Oregon, docket UM 903, dated November 9, 1998.

Q. IS THERE AN EIGHTH REASON?

A. Yes. It is that investors may expect a city or some other public entity to condemn all or part of a water utility and that the public entity will be required by a court to pay the utility the fair market value for it. Water utilities typically have assets that have a value, based on reproduction cost new, that is well in excess of book value. I have testified on the value of water utility properties and electric utility properties in various court cases in California, Utah and Oregon. Based on my experience, in situations where only a portion of the utility is being condemned, valuations based on both reproduction cost new less depreciation and the income approach indicate utility property has a value well in excess of book value. Investors would be aware that juries are expected to award potential condemnation values well in excess of book values even if the utility earns no more than its cost of equity.

Q. IS THERE A NINTH REASON?

A. Yes. It is based on investors recognizing merger and acquisition prices reported in Table 2, that have been well above book values, can be expected if the water utility is acquired. With such anticipated sale prices well above book values, such a water utility would also be priced above book values even if the water utility made no more than its cost of equity.

In summary, naive arithmetic models may suggest market prices would not be above book values unless investors expected water utilities to earn more than their costs of equity. The nine reasons listed above explain why one should not be surprised to find market prices exceed book values. Naive arithmetic models are too simple to explain all of the things of importance to investors and why it is reasonable to expect a positive value for "V" even if water utilities are expected to earn no more than their costs of equity.

Q. IF YOU DID NOT INCLUDE AN ESTIMATE OF VS GROWTH IN YOUR ESTIMATES OF SUSTAINABLE GROWTH, WOULD YOU HAVE TO ADJUST YOUR EQUITY COST ESTIMATES?

A. Yes. If the utilities in the water utilities sample are expected to issue more shares of common stock in the future (i.e., "S" is expected to be positive), but VS growth is excluded by the analyst, the exclusion of VS growth implies a hypothetical market price equal to book value and thus a value for "V" of zero. But if such a hypothetical assumption is made for the utilities in the water utilities sample, for consistency, the hypothetical price should also be assumed to be equal to book value to compute dividend yields. In that case, the hypothetical price would be lower and the dividend yield would have to more than double. This increase in average dividend yield (of more than 300 basis points) would more than offset the elimination of VS growth (of less than 150 basis points). Therefore, if consistent assumptions are made and only BR growth is recognized in the DCF analysis for water utilities, the implied average cost of equity increases by more than 150 basis points.

Q. DO YOU ADVOCATE USING SUCH HYPOTHETICAL PRICES IN THE DCF ANALYSIS?

A. No. A market-based cost of equity estimate should recognize VS growth and real market prices. The evidence indicates that investors can realistically expect both V and S to be positive, and thus stock prices (and dividend yields) already reflect expected VS growth. If investors expect VS growth for the water utilities sample and it is not recognized by the analyst, the analyst's estimate of the cost of equity will be biased downward.

Q. SHOULD THE COMMISSION RECOGNIZE VS GROWTH EVEN IF ARIZONA WATER DOES NOT PLAN TO ISSUES SHARES OF COMMON STOCK TO THE PUBLIC?

A. Yes. VS growth is part of the growth investors could reasonably expect for the utilities in the water utilities sample, not Arizona Water. If investors expect VS growth for those utilities and it is not recognized in the estimate of sustainable growth, the cost of equity for the water utilities sample will be understated. The inclusion of VS growth has nothing to do with whether Arizona Water does or does not have publicly-traded common stock or plans to issue additional common shares; it has to do with a correct estimate of the cost of equity for the water utilities sample.

Q. WHAT IS YOUR ESTIMATE OF AVERAGE SUSTAINABLE GROWTH?

A. Combining the evidence on expected VS and BR growth rates, the estimate of total sustainable growth is 7.7%. That value is developed in Table 12.

Q. ARE THERE OTHER INDICATORS OF FUTURE GROWTH THAT INVESTORS MAY RELY UPON WHEN PRICING SHARES OF WATER UTILITY COMMON STOCKS?

A. Yes. Other estimates of forward-looking growth are analysts' forecasts of future five-year EPS growth. Table 15 shows analysts' consensus forecasts of future EPS growth rates for two utilities in the water utilities sample and for the water utility industry that were reported by *First Call* on May 6, 2002, and *Value Line*'s May 3, 2002 forecasts of EPS growth for the three utilities in the water utilities sample that are available. The average of analysts' forecasts of growth is 7.0%.

Q. HOW DID YOU UTILIZE THIS INFORMATION ON DIVIDEND YIELDS AND ESTIMATED FUTURE GROWTH TO MAKE YOUR BENCHMARK DCF ESTIMATES?

A. I adopted an average of my estimate of sustainable growth and analysts' forecasts of growth to determine an overall average growth of 7.3%. I then used the constant growth DCF model specified in equation (1) to compute the DCF equity cost range for the four utilities in the water utilities sample. Table 16 shows the application of this specification of the DCF model to determine the estimated equity cost range of 11.0% to 11.1% for the average water utility in the water utilities sample. This range of equity costs for the average of the water utilities sample does ***not***, however, account for the additional risk faced by Arizona Water. In Section IV above, I concluded the additional equity return required by Arizona Water falls in a range of 100 to 150 basis points. Recognizing that risk premium range, this benchmark DCF equity cost indicates the cost of equity for Arizona Water falls in a range of 12.0% to 12.6%.

Q. DID YOU DEVELOP A SECOND BENCHMARK ESTIMATE OF THE COST OF EQUITY?

A. Yes. Another benchmark DCF estimate of the cost of equity was derived from similar data and a comparable analysis for the gas utilities sample in Table 3. Table 4 shows the average risk for the gas utilities sample is approximately the same as the average risk for the water utilities sample. The utilities in the gas utilities sample are all of the gas distribution utilities relied upon by ACC Staff to determine equity costs in the Black Mountain Gas Company, Docket No. G-03703A-01-0263, which have at least 65% of their revenues from gas operations (as reported by *C. A. Turner Utility Reports)* and have at least one bond rating of A or better published by Moody's or S&P. To be conservative, I reduce the equity costs for the gas distribution utilities by 50 basis points to determine another estimate of the required ROE for a water utility of risk comparable to the four in the water utilities sample. I then add a range of 100 to 150 basis points to the adjusted equity cost estimate to determine another equity cost estimate for Arizona Water.

Q. WHERE DID YOU CALCULATE DIVIDEND YIELDS FOR THIS SAMPLE?

A. Table 17 shows the calculation of dividend yields for the three-month and the twelve-month periods ending in April 2002.

Q. WHAT IS SHOWN IN TABLE 18?

A. Table 18 shows my calculations of sustainable growth based on *Value Line* forecasts for the gas utilities sample. I used the same method used to compute BR growth for the gas utilities sample that I used to compute BR growth for the water utilities sample. The sustainable growth rate estimates are computed by adding the BR growth estimates to estimates of VS growth.

Q. WHERE DID YOU DEVELOP THE ESTIMATES OF VS GROWTH?

A. In Table 19. Because the utilities in the gas utilities sample are not expected to issue as many shares of common stock as utilities in the water utilities sample and have lower market-to-book ratios, the estimated VS growth is smaller than it is for the water utilities sample.

Q. HAVE YOU ALSO EXAMINED ANALYSTS' FORECASTS OF FUTURE EPS GROWTH?

A. Yes, I have. Analysts' forecasts of EPS growth for the next five years are generally available to investors from a number of sources. Table 20 shows analysts' average forecasts as reported by *First Call* on May 8, 2002 as well as the most recent forecasts published by *Value Line* that were available to investors in May 2002. The average of those forecasts is 6.6%.

Q. WHERE DO YOU REPORT THE RESULTS OF YOUR DCF ANALYSIS FOR THE GAS UTILITIES SAMPLE?

A. Table 21 reports the results of the DCF analysis for the gas utilities sample. In making these estimates, I have adopted a growth rate of 6.4%, the average of the estimates of sustainable growth and analysts' forecasts of future 5-year EPS growth. To determine the equity cost that is a proxy for the cost of equity of the average utility in the water utilities sample, I reduced the equity cost estimates shown in Table 21 by 50 basis points. These data indicate that the average of the water utilities sample equity cost falls in a range of 11.1% to 11.2% and that Arizona Water has an equity cost that falls in a range of 12.1% to 12.7%.

VI. <u>Risk Premium Estimates of the Benchmark Cost of Equity</u>

Q. IS THERE CONCEPTUAL SUPPORT FOR ESTIMATING THE COST OF EQUITY WITH A RISK PREMIUM MODEL?

A. Yes. The finance principle that common stocks are generally more risky than bonds provides such support. Debt payments take precedent over distributions to common stockholders and thus a positive risk premium is expected unless investors anticipate hyper-inflation[11]. Such a risk premium combined with a forward-looking estimate of the cost of debt provides the basis for a risk premium estimate of the cost of equity.

Q. DO YOU EXPECT RISK PREMIUMS TO BE CONSTANT?

A. No. The theoretical work of Gordon and Halpern[12] as well as numerous empirical studies, including a 1989 study by Staff of the Oregon Public Utility Commission, a 1993 study by the Staff of the Virginia State Corporation Commission, and a 1997 decision of the CPUC, indicate that changes in the cost of equity, while moving in the same direction as changes in interest rates, are generally smaller than associated changes in interest rates. Thus, risk premiums change in the opposite direction to changes in interest rates. In the past, I have conducted empirical studies for gas utilities, telecommunications companies, and electric utilities that corroborate the Gordon and Halpern theory.

Q. HOW IS THE BALANCE OF THIS SECTION OF YOUR TESTIMONY ORGANIZED?

A. I present three equity cost estimates that were made with the risk premium approach. The methods are based on the assumption that risk premiums which have occurred in the past can be expected to continue into the future.

Q. PLEASE EXPLAIN YOUR FIRST RISK PREMIUM ANALYSIS.

A. The first analysis is presented in Table 22. Initially, I combined data on past returns earned by water utilities[13] and Baa corporate bond rates to determine the past relationship between interest rates and realized returns for water utilities. Panel A of Table 22 shows that realized ROEs for water utilities have decreased less than yields on Baa corporate

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11 Inflation is currently expected to be far below the hyper-inflation level.

12 "Bond Share Yield Spreads Under Uncertain Inflation," American Economic Review, 66 4 (September 1976) 559-565.

13 The data were compiled by the CPUC Water and Natural Gas Branch and reported in Table 2-4 of its report in CPUC Application 01-10-028.

bonds.

Next, in this study and the second risk premium study, I assumed that ROEs authorized by regulatory commissions provide, on average, unbiased estimates of the cost of equity facing the utilities at different points in time. Every commission decision will not provide every utility its cost of equity, but given the goals and responsibilities of regulatory commissions, one should expect, on average, that the cost of equity is awarded and thus the various commission determinations provide an unbiased source of data to conduct the risk premium analysis. In Federal Energy Regulatory Commission Docket No. ER93-465-000, et al., the Financial Analysis Branch of FERC also adopted state regulatory commission determinations of authorized ROEs to determine risk premiums for their cost of equity analysis.

Data shown in Table 14 indicate that, on average, water utilities followed by *C. A. Turner Utility Reports* have earned 88 basis points less than their authorized ROEs during the period 1991- 2001. For the analysis in Table 22, I made the conservative assumption that, on average, costs of equity equal authorized ROEs and are 40 basis points higher than realized ROES to compute the risk premiums.

Panel A shows that when Baa corporate bond rates dropped by an average of 83 basis points, ROEs dropped by an average of 30 basis points and risk premiums increased on average by 53 basis points. In relative terms, those changes mean that for every 100 basis point decrease in the Baa bond rate[14], the risk premium has increased by 64 basis points.

Panel B of Table 22 takes the data developed in Panel A and combines it with a range of consensus forecasts of the Baa bond rate compiled by Blue Chip in December 2001 for the period 2003 to 2004 to compute a forecasted range of equity costs for a

[14] The Baa corporate bond rate has been adopted for the risk premium analysis because such rates are expected to be more closely tied to utility equity costs than are Treasury security rates and because forecasts of the Baa corporate bond rate are widely available.

typical water utility. That range of forecasted future Baa corporate bond rates combined with the past relationship between Baa corporate rates and water utility ROEs indicates an estimated equity cost range of 11.3% to 11.4%. At May 23, 2002, the actual Baa/BBB utility bond rate was 8.14% and thus falls toward the top of the forecasted range of interest rates. With the 8.1% Baa/BBB bond rate, the indicated cost of equity for a water utility is 11.4%.

Q. PLEASE EXPLAIN YOUR SECOND RISK PREMIUM ANALYSIS.

A. A second risk premium analysis was made using data for gas distribution utilities. As in the prior study, ROEs authorized by regulatory commissions for different utilities at different points in time are assumed to equal, on average, the respective costs of equity. My analysis was made with the following model:

$$RP_i = A_0 + (A_1 \times Baa_i),$$

where RP_i is the risk premium computed by subtracting the measure of the interest rate (Baa corporate bond rate) from the authorized ROE for the particular commission decision, and A_0 and A_1 are the parameters estimated with a statistical regression. If -- as expected -- risk premiums increase when interest rates fall, the estimated slope (i.e., A_1) will be negative.

The results of the regression are shown in Table 23. I used data from 454 different litigated decisions during the period 1982 to 2002 to establish a database for this analysis. The -.51 value for the "slope (A_1)" coefficient means that as Baa corporate bond rates fall, the risk premium goes up. The large t-statistic of -51.4 supports a conclusion that it is better to assume risk premiums vary inversely with interest rates than to assume the risk premiums have been constant. The regression result indicates that the best estimate of the current risk premium is made by assuming the cost of equity for a typical gas utility drops by 49 basis points for every 100 basis point drop in Baa corporate bond rates.

The results in Table 23 are also used to estimate the range in which the cost of equity for the average utility in the water utilities sample falls at this time. In making that estimate, as before, I assumed that the cost of equity for a typical water utility is 50 basis points less than the cost of equity for the typical gas utility. After removing 50 basis points, the evidence in Table 23 indicates an equity cost range of 10.9% to 11.0% for the average utility in the water utilities sample. This evidence is used to estimate Arizona Water's cost of equity by combining it with the 100 to 150 basis point range required to reflect Arizona Water's added risk. That calculation indicates Arizona Water has a cost of equity that falls in a range of 11.9% to 12.5%.

Q. PLEASE DISCUSS YOUR THIRD RISK PREMIUM ANALYSIS?

A. My third risk premium estimate is made from historical data on actual returns for Moody's gas distribution utility stock index and Baa corporate bond rates for the period 1954 to 2000 displayed in Table 24. In this analysis, I recognized that while realized risk premiums over short periods may differ substantially from investor expectations, over a long period such as 1954 to 2000, the average difference between realized premiums and expected premiums is expected to converge. Thus, the average of annual total market returns on the gas utility stock index, less the yield on Baa corporate bonds for the period, provide data to derive an estimate of the average risk premium investors have demanded in the past. Assuming investors require the same risk premium in the future as in the past, with a forecasted range of 8.0% to 8.2% for Baa corporate bonds, the estimate of the cost of equity for a typical gas utility falls in the range of 11.7% to 11.9%. Again assuming a conservative 50 basis point difference between the required ROE for gas and water utilities, the indicated cost of equity for the average utility in the water utilities sample falls in the range of 11.2% to 11.4% and Arizona Water's cost of equity falls in a range of 12.2% to 12.9%.

VII. Summary, Conclusions and Perspective

Q. WHAT EQUITY RETURN DO YOU RECOMMEND THE COMMISSION APPROVE FOR ARIZONA WATER?

A. I recommend the Commission authorize an equity return of no less than 12.4%.

The fair rate of return for Arizona Water should be determined by recognizing that Arizona Water is considerably smaller in terms of operating revenues and net plant than the larger, publicly-traded water utilities I have relied upon in the water utilities sample to determine equity costs. I presented evidence that smaller companies in general, and small water utilities in particular, have higher costs of equity than larger companies. Arizona Water is also more risky than other water utilities because it faces substantial risk from the need to build and operate arsenic treatment facilities, is more risky because it has its rates based on historical test years that increases the uncertainty of cost recovery, has less financing flexibility than the larger, publicly-traded utilities and has debt financing limitations it did not have in the past. Based on my analyses and recognition of Arizona Water's other risks, I recommended that the Commission add 100 to 150 basis points to the cost of equity benchmarks for larger, publicly-traded water utilities to account for that additional risk.

The various equity cost estimates that have been made are summarized in Table 25. Equity cost benchmarks were determined from data for the gas utilities sample as well as the water utilities sample. These equity cost estimates are generally consistent with ROEs the ACC has authorized in past cases reported in Table 10. Recognizing the range of estimated equity cost benchmarks and the 100 to 150 basis point risk premium range, I conclude that Arizona Water's cost of equity falls in a range of 11.9% to 12.9% and recommend that Arizona Water be authorized an ROE of no less than 12.4% at this time.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes.

Arizona Water Company

Table 1

Selected Characteristics of Water Utilities Sample

Companies in Sample[a]	% Water Revenues[b]	S&P Bond Rating[b]	Moody's Bond Rating[b]	Operating Revenues ($millions)	Net Plant ($millions)	
1 American States	92%	A+	A1	$198	$496	
2 California Water	100%	AA-	Aa3	$247	$694	
3 Philadelphia Suburban	98%	AA-	NR	$307	$1,237	
4 SJW Corp	98%	NR	NR	$136	$243	
Average of Four Company Sample				$222	$668	
Arizona Water[c]				$33	$139	
Companies Not in Sample[a]						**Reason Not Included**
American Water Works	94%	A+	A3	$1,439	$5,229	merger in progress
Connecticut Water Service	100%	NR	NR	$45	$170	anticipated merger
Middlesex Water	100%	A+	A2	$60	$182	anticipated merger
Southwest Water	42%	NR	NR	$116	$118	% of water revenues

Sources:
_a/ List of water utilities relied upon by ACC Staff in Docket No. W-01427A-01-0487
_b/ *C.A. Turner Utility Reports*, May 2002.
_c/ 2001 Arizona Water Annual Report to ACC.

5/17/02

Table 2

Premiums Received by Investors from Recent Mergers and Acquistions of Water Utilities

Company	Approximate Date of Aquisition or Merger	Highest Price in Year Prior to Announcement	Value at Time of Merger or Acquistion	Basis	Premium
Aquarion	August 1999	$27.40	$37.05	cash	35%
United Water Resources	July 2000	$25.00	$35.30	cash	41%
E-Town	Year-end 2000	$48.30	$68.00	cash	41%
Dominguez	May 2000	$21.50	$33.75	stock	57%
Consumers Water	March 1999	$20.80	$33.10	stock	59%
American Water Works	Proposed	$34.00	$46.00	cash	35%
Average					45%

Arizona Water Company

Table 3

Selected Characteristics of Gas Utilities Sample

Companies in Sample_a/	Percentage of Gas Revenues_b/	S&P Bond Rating_b/	Moody's Bond Rating_b/	Operating Revenues_b/ ($millions)	Net Plant_b/ ($millions)	
1 AGL Resources	76%	A-	A3	$1,080	$2,085	
2 Atmos Energy	96%	A-	A3	$1,271	$1,335	
3 Laclede Gas	93%	AA-	Aa3	$852	$575	
4 NICOR	83%	AA	Aa1	$2,544	$1,769	
5 NW Natural	98%	A	A2	$647	$965	
6 Peoples Energy	66%	AA-	Aa2	$1,931	$1,745	
7 Piedmont Natural	86%	A	A2	$929	$1,119	
8 WGL Holdings	100%	AA-	Aa2	$1,173	$1,530	
Average for Gas Utilities Sample				$1,303	$1,390	
Companies Not in Sample_a/						**Reason Not Included**
Cascade Natural Gas		BBB+	Baa1			bond rating
Energen	64%					% gas revenues
NUI Corp	46%					% gas revenues
New Jersey Resources	51%					% gas revenues
ONEOK	21%					% gas revenues
SEMCO Energy	59%	BBB	Baa2			bond rating
South Jersey Industries	53%					% gas revenues
Southwest Gas		BBB-	Baa2			bond rating
UGI Corp	24%					% gas revenues

Sources:
_a/ List of gas utilites relied upon by ACC Staff in Docket No. G-03703A-01-0263.
_b/ *C.A. Turner Utility Reports*, May 2002.

5/8/02

Arizona Water Company

Table 4

Beta Risk and Safety Rankings of Gas and Water Utilities Samples

	Beta	Safety Rank
Gas Distribution Utilities		
1 AGL Resources	0.60	2
2 Atmos Energy	0.55	3
3 Laclede Gas	0.55	2
4 NICOR	0.60	1
5 NW Natural	0.60	2
6 Peoples Energy	0.70	1
7 Piedmont Natural	0.60	2
8 WGL Holdings	0.60	1
Average	0.60	1.8
Water Utilities		
1 American States	0.65	3
2 California Water	0.60	2
3 Philadelphia Suburban	0.60	2
4 SJW Corp_b/	0.55	2
Average	0.60	2.3

Sources:

_a/ *Value Line,* Summary and Index, May 3, 2002 with the exception of SJW Corp.

_b/ From the *Value Line* Expanded Edition Summary and Index, dated May 3, 2002.

5/07/02

Arizona Water Company

Table 5

Largest Companies
in Each of Ten Deciles

Table 7-2

Size-Decile Portfolios of the NYSE/AMEX/NASDAQ, Largest Company and Its Market Capitalization by Decile
September 30, 2001

Decile	Market Capitalization of Largest Company (in thousands)	Company Name
1-Largest	$484,237,211	General Electric Co.
2	12,379,336	TXU Corp.
3	5,252,063	Equifax Inc.
4	2,599,543	Bergen Brunswig Corp.
5	1,656,910	Pentair inc.
6	1,114,792	La-Z-Boy Inc.
7	717,946	Cabot Oil & Gas Corp.
8	462,105	Star Gas Partners LP
9	269,275	Ackerley Group Inc.
10-Smallest	104,356	Huttig Building Products Inc.

Source: Center for Research in Security Prices, University of Chicago.

Source: Ibbotson Associates, 2002 SBBI Yearbook, Valuation Edition, Page 119.

Arizona Water Company

Table 6

Betas Estimated
with Monthly Data

Table 7-5

Long-Term Returns in Excess of CAPM Estimation for Decile Portfolios of the NYSE/AMEX/NASDAQ 1926–2001

Decile	Beta*	Arithmetic Mean Return	Realized Return in Excess of Riskless Rate**	Estimated Return in Excess of Riskless Rate†	Size Premium (Return in Excess of CAPM)
1-Largest	0.91	11.69%	6.46%	6.74%	-0.28%
2	1.04	13.27%	8.04%	7.71%	0.33%
3	1.09	13.94%	8.71%	8.13%	0.59%
4	1.13	14.44%	9.21%	8.38%	0.83%
5	1.16	14.92%	9.69%	8.65%	1.04%
6	1.18	15.37%	10.15%	8.79%	1.36%
7	1.24	15.66%	10.43%	9.17%	1.26%
8	1.28	16.66%	11.43%	9.50%	1.94%
9	1.34	17.61%	12.38%	9.97%	2.41%
10-Smallest	1.42	21.11%	15.89%	10.55%	5.33%
Mid-Cap, 3-5	1.12	14.25%	9.02%	8.30%	0.72%
Low-Cap, 6-8	1.22	15.70%	10.47%	9.05%	1.42% a/
Micro-Cap, 9-10	1.36	18.63%	13.40%	10.10%	3.30%

*Betas are estimated from monthly portfolio total returns in excess of the 30-day U.S. Treasury bill total return versus the S&P 500 total returns in excess of the 30-day U.S. Treasury bill, January 1926–December 2001.

**Historical riskless rate is measured by the 76-year arithmetic mean income return component of 20-year government bonds (5.23 percent).

†Calculated in the context of the CAPM by multiplying the equity risk premium by beta. The equity risk premium is estimated by the arithmetic mean total return of the S&P 500 (12.65 percent) minus the arithmetic mean income return component of 20-year government bonds (5.23 percent) from 1926–2001.

Note: a/ 3.30% - 1.42% = 1.88% risk adder for being in Micro-Cap instead of Low-Cap.

Source: Ibbotson Associates, 2002 SBBI Yearbook, Valuation Edition, Page 125.

Arizona Water Company

Table 7

Betas Estimated
with Annual Data

Table 7-8

Long-Term Returns in Excess of CAPM Estimation for Decile Portfolios of the NYSE/AMEX/NASDAQ, with Annual Beta
1926–2001

Decile	Annual Beta*	Arithmetic Mean Return	Realized Return in Excess of Riskless Rate**	Estimated Return in Excess of Riskless Rate†	Size Premium (Return in Excess of CAPM)	
1-Largest	0.94	11.69%	6.46%	6.96%	-0.50%	
2	1.05	13.27%	8.04%	7.77%	0.27%	
3	1.09	13.94%	8.71%	8.09%	0.63%	
4	1.17	14.44%	9.21%	8.67%	0.54%	
5	1.21	14.92%	9.69%	8.96%	0.73%	
6	1.20	15.37%	10.15%	8.92%	1.23%	
7	1.30	15.66%	10.43%	9.66%	0.77%	
8	1.38	16.66%	11.43%	10.22%	1.22%	
9	1.46	17.61%	12.38%	10.82%	1.55%	
10-Smallest	1.65	21.11%	15.89%	12.23%	3.65%	
Mid-Cap, 3-5	1.13	14.25%	9.02%	8.42%	0.60%	
Low-Cap, 6-8	1.27	15.70%	10.47%	9.43%	1.04%	_a/
Micro-Cap, 9-10	1.51	18.63%	13.40%	11.23%	2.17%	

*Betas are estimated from annual portfolio total returns in excess of the 30-day U.S. Treasury bill total return versus the S&P 500 index total returns in excess of the 30-day U.S. Treasury bill, January 1926–December 2001.

**Historical riskless rate is measured by the 76-year arithmetic mean income return component of 20-year government bonds (5.23 percent).

†Calculated in the context of the CAPM by multiplying the equity risk premium by beta. The equity risk premium is estimated by the arithmetic mean total return of the S&P 500 (12.65 percent) minus the arithmetic mean income return component of 20-year government bonds (5.23 percent) from 1926–2001.

Note: a/ 2.17% - 1.04% = 1.13% risk adder for being in Micro-Cap instead of Low-Cap.

Source: Ibbotson Associates, 2002 SBBI Yearbook, Valuation Edition, Page 131.

Table 8

Small Firm Equity Cost Differrential: Case Study
Based on a Comparison of DCF Equity Costs for
Smaller and Larger California Class A Water Utilities

1987-1997[a]

	Larger California Class A's[b]			Smaller California Class A's[c]			
	Do/Po	Estimated Growth[d]	Equity Cost Estimate[e]	Do/Po	Estimated Growth[d]	Equity Cost Estimate[e]	Smaller Utilities Minus Larger Utilities
1987	6.60%	7.17%	14.24%	5.38%	10.06%	15.98%	1.74%
1988	6.75%	6.30%	13.48%	5.81%	9.08%	15.42%	1.94%
1989	7.10%	6.30%	13.84%	6.47%	7.00%	13.93%	0.09%
1990	7.24%	6.19%	13.87%	6.96%	7.51%	14.99%	1.11%
1991	6.94%	6.29%	13.67%	6.64%	6.24%	13.30%	-0.36%
1992	6.18%	5.96%	12.50%	6.50%	6.71%	13.65%	1.14%
1993	5.32%	5.68%	11.30%	5.49%	6.31%	12.15%	0.85%
1994	6.03%	4.40%	10.70%	5.80%	4.86%	10.94%	0.25%
1995	6.44%	3.86%	10.55%	6.44%	4.88%	11.64%	1.09%
1996	5.60%	4.06%	9.88%	5.77%	5.58%	11.67%	1.79%
1997	4.93%	3.31%	8.40%	4.52%	4.89%	9.64%	1.23%
				Average Difference:			0.99%
				t-statistic			(1.405)[f]

Notes:

_a/ Limited to the period for which Dominguez Water Company data were available. 1998 excluded due to pending buyout.
_b/ American States and California Water Service.
_c/ Dominguez Water Company and SJW Corporation.
_d/ Averages past dividend per share growth, earnings per share growth and sustainable growth.
_e/ DCF equity cost computed as $k = (D_0/P_0) \times (1+g) + g$.
_f/ Significant at the 90% level.

Arizona Water Company

Table 9

Actual and Forecasted Baa Bond Rates

Year/Month	Baa Corporate Bonds
1996-[a/]	8.05%
1997-[a/]	7.87%
1998-[a/]	7.22%
1999-[a/]	7.88%
2000-[a/]	8.37%
2001-[a/]	7.95%
May 2002-[b/]	8.14%
Forecast for 2004-[c/]	8.20%

Sources:
_a/ Federal Reserve
_b/ Value Line, *Selection & Opinion*, May 31, 2002 for recent selected yields at May 23, 2002.
_c/ Blue Chip *Financial Forecasts*, December 2001.

Arizona Water Company

Table 10

Recent Authorized Returns on Equity
For Larger Arizona Water, Sewer and Gas Utilities

Company	Decision Number	Decision Date	Authorized ROE
Citizens Utilities Company; Agua Fria Water Division; Sun City Water Company; Sun City Sewer Company and Sun City West Utilities Company	60172	May 7, 1997	10.50%
Paradise Valley Water Company	60220	May 27, 1997	11.00%
Far West Water Company	60437	Sept 29, 1997	11.50%
Saddlebrooke Utility Company	61008	July 16, 1998	11.30%
Paradise Valley Water Company	61831	July 20, 1999	11.00%
Bermuda Water Company	61854	July 21, 1999	12.00%
Pima Utility Company (Sewer)	62184	Jan 5, 2000	11.75%
Far West Water & Sewer Co. (Water)	62649	June 13, 2000	11.50%
Southwest Gas Corporation	64172	Oct. 30, 2001	11.00%
Arizona Water Company (Northern Group)	64282	Dec. 28, 2001	10.25%

Table 11

Average Dividend Yields for Water Utilities Sample

	3-Month D_0/P_0	12-Month D_0/P_0	D_0_a/	12-month High Stock Price_b/	12-month Low Stock Price_b/	3-Month High Stock Price_c/	3-Month Low Stock Price_c/
1 American States	3.61%	3.92%	$1.30	$39.75	$28.50	$39.75	$32.90
2 California Water	4.51%	4.45%	$1.12	$27.75	$23.00	$26.89	$23.10
3 Philadelphia Suburban	2.20%	2.49%	$0.51	$24.64	$17.60	$24.61	$22.04
4 SJW Corp	3.31%	3.27%	$2.68	$91.25	$74.65	$84.50	$78.01
Average	3.41%	3.53%					

<u>Notes and Sources</u>:

_a/ Dividends paid during last 12 months (as of April 30, 2002)
_b/ Prices during the last 12 months as of April 30, 2002.
_c/ Prices during the last 3 months as of April 30, 2002.

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Table 12

Estimates of Sustainable Growth for the Water Utilities Sample

	Retention Ratios Derived from Value Line Forecasts-[a,e]	Expected ROE-[b]	Forecast of BR-[c] Growth	VS Growth-[d]	Average Sustainable Growth
1 American States	0.49	11.0%	5.6%	0.4%	6.0%
2 California Water	0.42	11.5%	5.0%	2.2%	7.2%
3 Philadelphia Suburban	0.54	14.0%	7.8%	3.3%	11.1%
4 SJW Corp-[e]	0.56	11.1%	6.4%	0.0%	6.4%
Average of column	0.50	11.9%	6.2%	1.5%	7.7%

Notes and Sources:

_a/ Based on *Value Line* forecasts of DPS and EPS for the period 2005-2007 published at May 3, 2002 or past retention ratios grown by past growth.
_b/ Value Line forecast of ROE if available, otherwise past average earned ROE.
_c/ BR growth adjusted for year-end ROE forecast by *Value Line*.
_d/ Estimated VS growth derived in Table 13.
_e/ Based on historical information for 1996-2000 reported by *Value Line*. Retention ratio computed by growing past DPS and EPS by past growth for five years. *Value Line* forecasts are not available.

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Table 13

Estimate of Expected VS Growth for Water Utilities Sample

	Stock Financing Rate (S)_a/ (a)	Market to Book Ratio_b/ (b)	V (c)	VS growth (d)
1 American States	0.87%	1.93	0.48	0.42%
2 California Water	4.32%	2.03	0.51	2.19%
3 Philadelphia Suburban	4.57%	3.52	0.72	3.27%
4 SJW Corp	0.00%	1.69	0.41	0.00%
Average of Column		2.29	0.53	1.47%

Notes and Sources:
_a/ From *Value Line* data reported May 3, 2002.
_b/ As reported by C. A. Turner in May 2002.

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Table 14

Comparisons of Realized and Authorized ROEs and Market-to-Book Ratios for Water Utilities and Value Line's Industrical Composite: 1991 - 2001

	Earned ROE	Authorized ROE	Earned Less Authorized ROE	Water Utilities M/B	Industrial Composite M/B
1991	10.00	12.82	-2.82	1.36	2.43
1992	11.60	12.73	-1.13	1.49	3.10
1993	10.40	12.72	-2.32	1.55	3.18
1994	11.40	11.96	-0.56	1.28	2.90
1995	9.70	11.99	-2.29	1.33	3.15
1996	10.50	11.30	-0.80	1.48	3.50
1997	11.00	11.14	-0.14	1.73	4.13
1998	11.10	10.87	0.23	2.06	4.83
1999	11.10	10.87	0.23	2.50	5.21
2000	10.30	10.74	-0.44	2.06	4.85
2001	10.90	10.57	0.33	2.27	3.35
Average			-0.88		

Sources:

_a/ Year-end *C.A. Turner Utility Reports*

_b/ *Value Line* Industrial Composite as reported January 25, 2002.

Table 15

Analysts Forecasts of Future Earnings Growth for Water Utilities Sample

	First Call_a/	Value Line_b/	Average
1 American States	4.5%	7.0%	5.8%
2 California Water	_c/	8.5%	8.5%
3 Philadelphia Suburban	7.0%	10.5%	8.8%
4 SJW Corp	_c/	_d/	
Averages:	6.3% _e/	7.8%	7.0%

Notes and Sources:

_a/ First Call (formerly IBES) average forecasts reported on Internet on May 6, 2002 .

_b/ *Value Line* forecasts as of May 3, 2002.

_c/ Not included if one forecast or less.

_d/ *Value Line* does not provide forecasts for SJW Corp.

_e/ Industry average repored by First Call.

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Table 16

DCF Equity Cost Ranges Estimated for Water Utilities
Sample and Arizona Water

	D_0/P_0	D_1/P_0 [a]	Growth [b]	Water Utilities Sample Equity Cost [a]	Arizona Water Equity Cost [c]
3-Month Dividend Yield	3.4%	3.7%	7.3%	11.0%	12.0%
12-Month Dividend Yield	3.5%	3.8%	7.3%	11.1%	12.6%

Notes and Sources:

_a/ Based on $D_1 = D_0 \times (1 + g)$.
_b/ Average of estimated sustainable growth and range of growth predicted by analysts. See Tables 12 and 15.
_c/ Water utilities sample equity cost plus 100 to 150 basis points.

5/8/02

Table 17

Average Dividend Yields for Gas Utilities Sample

	3-Month D_0/P_0	12-Month D_0/P_0	D_0_a/	12-month High Stock Price_b/	12-month Low Stock Price_b/	3-Month High Stock Price_c/	3-Month Low Stock Price_c/
1 AGL Resources	4.80%	5.05%	$1.08	$24.50	$18.95	$24.34	$20.95
2 Atmos Energy	5.27%	5.36%	$1.17	$24.85	$19.45	$24.55	$20.26
3 Laclede Gas	5.74%	5.71%	$1.34	$25.48	$21.75	$24.88	$22.00
4 NICOR	4.06%	4.43%	$1.78	$49.00	$34.00	$49.00	$39.68
5 NW Natural	4.66%	4.97%	$1.26	$30.30	$21.65	$30.29	$24.20
6 Peoples Energy	5.46%	5.37%	$2.05	$42.94	$34.35	$40.18	$35.26
7 Piedmont Natural	4.49%	4.71%	$1.56	$37.95	$29.19	$37.95	$31.80
8 WGL Holdings	4.72%	4.62%	$1.26	$29.75	$25.26	$27.95	$25.71
Average	4.90%	5.03%					

Notes and Sources:

_a/ Dividends paid during last 12 months (as April 30, 2002)

_b/ Prices during the last 12 months as of April 30, 2002.

_c/ Daily Prices reported by Yahoo! for February 1, 2002 to April 30, 20021.

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Table 18

Forecasts of Sustainable Growth for Gas Utilities Sample

	Retention Ratios Derived from Value Line Forecasts_a/	Forecasted ROE	Forecast of BR_b/ Growth	VS Growth_c/	Average Sustainable Growth	
1 AGL Resources	0.45	12.5%	5.8%	0.2%	6.0%	
2 Atmos Energy	0.39	14.0%	5.6%	2.5%	8.0%	
3 Laclede Gas	0.36	12.0%	4.4%	0.4%	4.8%	
4 NICOR	0.49	21.5%	11.1%	0.0%	11.1%	_d/
5 NW Natural	0.46	11.0%	5.2%	0.4%	5.6%	
6 Peoples Energy	0.47	14.0%	6.8%	0.0%	6.8%	
7 Piedmont Natural	0.37	12.5%	4.8%	0.6%	5.3%	
8 WGL Holdings	0.49	12.5%	6.3%	0.3%	6.7%	
Average of column	0.43	13.8%	6.2%	0.6%	6.2%	

<u>Notes and Sources</u>:

_a/ Value Line forecasts of DPS and EPS growth and ROE as of March 22, 2001.

_b/ BR growth adjusted for year-end ROE forecast by *Value Line*.

_c/ See Table 19.

_d/ Not included in average.

5/8/02

Table 19

Estimate of Expected VS Growth for Gas Utilities Sample

	Stock Financing Rate (S)_a/ (a)	Market to Book Ratio_b/ (b)	V (c)	VS growth (d)
1 AGL Resources	0.46%	1.92	0.48	0.22%
2 Atmos Energy	6.20%	1.66	0.40	2.47%
3 Laclede Gas	1.22%	1.55	0.35	0.43%
4 NICOR	0.00%	2.93	0.66	0.00%
5 NW Natural	1.10%	1.60	0.38	0.41%
6 Peoples Energy	0.00%	1.73	0.42	0.00%
7 Piedmont Natural	1.09%	2.03	0.51	0.55%
8 WGL Holdings	0.82%	1.67	0.40	0.33%
Average of Column		1.89	0.45	0.55%

Notes and Sources:

_a/ From Value Line data reported March 22, 2002.

_b/ As reported by C. A. Turner in May 2002.

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Table 20

Analysts' Forecasts of Future Earnings Growth for Gas Utilities Sample

	First Call_a/	Value Line_b/	Average
1 AGL Resources	8.0%	9.5%	8.8%
2 Atmos Energy	6.0%	9.0%	7.5%
3 Laclede Gas	3.0%	7.0%	5.0%
4 NICOR	5.0%	8.0%	6.5%
5 NW Natural	5.0%	7.5%	6.3%
6 Peoples Energy	6.0%	7.5%	6.8%
7 Piedmont Natural	5.0%	6.5%	5.8%
8 WGL Holdings	4.5%	7.5%	6.0%
Averages	5.3%	7.8%	6.6%

Notes and Sources:

_a/ First Call average forecasts reported on Internet on May 8, 2002.

_b/ *Value Line* forecasts as of March 22, 2002.

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Table 21

DCF Equity Cost Ranges for Water Utilities Sample and Arizona Water
Based on Data for Gas Utilities Sample

	D_0/P_0	D_1/P_0[a]	Growth[b]	Gas Utilities Sample Equity Cost[c]	Benchmark Water Utilities Sample Equity Cost[d]	Arizona Water Equity Cost
3-Month Dividend Yield	4.9%	5.2%	6.4%	11.6%	11.1%	12.1%
12-Month Dividend Yield	5.0%	5.3%	6.4%	11.7%	11.2%	12.7%

Notes and Sources:
_a/ Computed as $D_1 = D_0 \times (1 + g)$.
_b/ Average of estimated sustainable growth and range of growth predicted by analysts. See Tables 18 and 20.
_c/ Based on constant growth DCF model.
_d/ Assumes equity cost is 50 basis points lower.

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Arizona Water Company

Table 22

Water Utility Risk Premiums Computed with Past ROEs and Forecasted Cost of Equity

Panel A

	Baa Corporate Bond Rates_b/	Average Baa Corporate Bond Rate	Realized ROE_a/	Average ROE	Risk Premium_d/	Average Risk Premium
1991-1995						
1991	9.80%		12.00%		2.60%	
1992	8.98%		10.51%		1.93%	
1993	7.93%		11.60%		4.07%	
1994	8.63%		10.71%		2.48%	
1995	8.20%	8.71%	11.13%	11.19%	3.33%	2.88%
1996-2000						
1996	8.05%		11.60%		3.95%	
1997	7.87%		11.57%		4.10%	
1998	7.22%		10.91%		4.09%	
1999	7.88%		10.56%		3.08%	
2000	8.37%	7.88%	9.81%	10.89%	1.84%	3.41%
Differences in Averages:		-0.83%		-0.30%		0.53%
Relative Change		-100		-36		64

Panel B:

Forecasts of Baa Corporate Rate_c/	Estimated Risk Premium_d/	Forecasted Equity Cost
8.00%	3.33%	11.3%
8.20%	3.21%	11.4%

<u>Notes and Sources</u>:

_a/ Source: Tables 2-4 of CPUC WNGB Report, dated March 2002, in A. 01-10-028.

_b/ Past Baa rates reported by the Federal Reserve.

_c/ Range of consensus forecasts reported by *Blue Chip*, December 2001 for 2003 to 2004. As of May 23, 2002, the Baa utility bond rate was 8.14%.

_d/ Based on evidence reported by C. A. Turner Utility Reports at year-end for the last ten years, the cost of equity has been at least 40 basis points higher than the realized ROEs. See Table 14.

Arizona Water Company

Table 23

Risk Premium Analysis
Regression Analysis of Risk Premiums Based on Authorized Returns for Natural Gas Utility Stocks-[a] and Baa Corporate Bond Rates
1982-2002

Regresssion Formula-[c]: Risk Premium = A_0 + A_1 x Baa Corporate Rate

Regression Output:	
Constant (A_0)	0.0745
Std Err of Y Est	0.0077
R Squared	0.8541
No. of Observations	454
Degrees of Freedom	452
Slope (A_1)	-0.510
Std Err of Coef.	0.010
t-statistic	-51.4

	Equity Cost Estimate		Predicted Premium-[c]	Forecasted Baa Corporate Bond Rate-[b]
Bottom	11.37%	=	3.37% +	8.00%
Top	11.47%	=	3.27% +	8.20%

Estimated Equity Cost for the Average Utility in Water Utilities Sample:

Bottom	=	10.9%
Top	=	11.0%

Notes and Sources:

_a/ Sources: Annual Surveys of Gas Rate Cases, *Public Utilities Fortnightly,* KAN Rate of Return Data Books, Regulatory Research Associates and the Federal Reserve.

_b/ Range of consensus forecasts of rates for Baa Corporate bonds for 2003-2004 as of December 2001 as reported by Blue Chip.

_c/ Regression analysis assumes 8-month lag between Baa bond rate and the date of respective commission orders.

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Arizona Water Company

Table 24

Risk Premium Analysis
Comparison of Total Returns on Moody's Natural Gas Stock Index and Baa Corporate Bond Rates

	Rates on Baa Corporate Bonds-[a]	Moody's Natural Gas Price Index-[b]	Annual Average Dividend-[b]	Index Gain/Loss	Dividend Yield	Total Gas Stock Return	Risk Premium
1954	3.45%	26.47					
1955	3.62%	28.10	1.32	6.16%	4.99%	11.14%	7.69%
1956	4.37%	28.23	1.43	0.46%	5.09%	5.55%	1.93%
1957	5.03%	25.78	1.49	-8.68%	5.28%	-3.40%	-7.77%
1958	4.85%	38.71	1.53	50.16%	5.93%	56.09%	51.06%
1959	5.28%	39.59	1.63	2.27%	4.21%	6.48%	1.63%
1960	5.10%	48.21	1.79	21.77%	4.52%	26.29%	21.01%
1961	5.10%	64.96	1.91	34.74%	3.96%	38.71%	33.61%
1962	4.92%	59.73	2.01	-8.05%	3.09%	-4.96%	-10.06%
1963	4.85%	64.62	2.13	8.19%	3.57%	11.75%	6.83%
1964	4.81%	68.24	2.27	5.60%	3.51%	9.11%	4.26%
1965	5.02%	64.31	2.40	-5.76%	3.52%	-2.24%	-7.05%
1966	6.18%	53.50	2.75	-16.81%	4.28%	-12.53%	-17.55%
1967	6.93%	50.49	2.67	-5.63%	4.99%	-0.64%	-6.82%
1968	7.23%	53.80	2.79	6.56%	5.53%	12.08%	5.15%
1969	8.65%	43.88	2.88	-18.44%	5.35%	-13.09%	-20.32%
1970	9.12%	52.33	2.97	19.26%	6.77%	26.03%	17.38%
1971	8.38%	47.86	3.06	-8.54%	5.85%	-2.69%	-11.81%
1972	7.93%	53.54	3.10	11.87%	6.48%	18.35%	9.97%
1973	8.48%	43.43	3.21	-18.88%	6.00%	-12.89%	-20.82%
1974	10.63%	29.71	3.31	-31.59%	7.62%	-23.97%	-32.45%
1975	10.56%	38.29	3.43	28.88%	11.54%	40.42%	29.79%
1976	9.12%	51.80	3.65	35.28%	9.53%	44.82%	34.26%
1977	8.99%	50.88	3.85	-1.78%	7.43%	5.66%	-3.46%
1978	9.94%	45.97	4.07	-9.65%	8.00%	-1.65%	-10.64%
1979	12.06%	53.50	4.33	16.38%	9.42%	25.80%	15.86%
1980	14.64%	56.61	4.59	5.81%	8.58%	14.39%	2.33%
1981	16.55%	53.50	4.95	-5.49%	8.74%	3.25%	-11.39%
1982	14.14%	50.62	5.28	-5.38%	9.87%	4.49%	-12.06%
1983	13.75%	55.79	5.45	10.21%	10.77%	20.98%	6.84%
1984	13.40%	69.70	5.71	24.93%	10.23%	35.17%	21.42%
1985	11.58%	76.58	6.06	9.87%	8.69%	18.57%	5.17%
1986	9.97%	90.89	5.68	18.69%	7.42%	26.10%	14.52%
1987	11.29%	77.25	5.86	-15.01%	6.45%	-8.56%	-18.53%
1988	10.65%	86.76	6.15	12.31%	7.96%	20.27%	8.98%
1989	9.82%	117.05	6.45	34.91%	7.43%	42.35%	31.70%
1990	10.43%	108.86	6.70	-7.00%	5.72%	-1.27%	-11.09%
1991	9.26%	124.32	6.94	14.20%	6.38%	20.58%	10.15%
1992	8.81%	138.79	7.08	11.64%	5.69%	17.33%	8.07%
1993	7.69%	154.06	7.23	11.00%	5.21%	16.21%	7.40%
1994	9.10%	126.96	7.36	-17.59%	4.78%	-12.81%	-20.50%
1995	7.49%	155.94	7.48	22.83%	5.89%	28.72%	19.62%
1996	7.89%	166.64	8.01	6.86%	5.14%	12.00%	4.51%
1997	7.32%	191.04	7.99	14.64%	4.79%	19.44%	11.55%
1998	7.23%	177.24	8.12	-7.22%	4.25%	-2.97%	-10.29%
1999	8.19%	166.84	8.18	-5.87%	4.62%	-1.25%	-8.48%
2000	8.02%	200.68	8.22	20.28%	4.93%	25.21%	17.02%
					Average Risk Premium		3.67%

Equity Cost Forecast	Forecast of Baa Bond Rates-[c]	Gas Utility Equity Cost	Benchmark Water Utilities Sample Equity Cost	Arizona Water Equity Cost
Low	8.0%	11.7%	11.2%	12.2%
High	8.2%	11.9%	11.4%	12.9%

Sources and Notes:

a/ U. S. Federal Reserve. Monthly rates for December of the indicated year..

b/ Mergent, Moody's 2001 Public Utility Manual.

c/ Range of forecasts for 2003-2004 compiled by Blue Chip, December 2001.

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Arizona Water Company

Table 25

Summary Table: Estimated Cost of Equity Ranges for Water Utilites Sample and Arizona Water

	Estimated Benchmark Ranges of Equity Costs for Water Utilities Sample		Estimated Range of Equity Costs for Arizona Water	
Discounted Cash Flow Estimates				
Based on Water Utilities	11.0% to	11.1%	12.0% to	12.6%
Based on Gas Utilities	11.1% to	11.2%	12.1% to	12.7%
Risk Premium Analyses Estimates				
Based on Water Utilities	11.3% to	11.4%	12.3%	12.9%
Based on Gas Utilities Authorized ROEs	10.9% to	11.0%	11.9%	12.5%
Based on Moody's Gas Utilities Index	11.2% to	11.4%	12.2%	12.9%
Estimated Equity Cost Range for Arizona Water			11.9%	12.9%

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